BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of Rate Increases and Revised Rate Schedule and Rules	)	Docket No. 2008-0083

HECO
2009 TEST YEAR

HECO REBUTTAL TESTIMONIES, EXHIBITS, AND WORKPAPERS

May 22, 2009

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

May 22, 2009

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, First Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0083
HECO 2009 Test Year Rate Case
HECO Rebuttal Testimonies, Exhibits, and Workpapers

Enclosed for filing are Hawaiian Electric Company, Inc.'s ("HECO") Rebuttal Testimonies, Exhibits, and Workpapers for the following HECO witnesses:

- HECO RT-1 – Robert A. Alm;
- HECO RT-10A – Lynne T. Unemori;
- HECO RT-19 – Roger A. Morin, Ph.D.;
- HECO RT-20 – Tayne S. Y. Sekimura;
- HECO RT-21 – Steven M. Fetter;
- HECO RT-23 – Tayne S. Y. Sekimura.

Very truly yours,

Enclosure

cc: Division of Consumer Advocacy
Department of Defense

Hawaiian Electric Company, Inc.

Docket No. 2008-0083

Application for Approval of Rate Increases and
Revised Rate Schedules and Rules

REBUTTAL TESTIMONIES AND EXHIBIT SPONSORSHIP LIST

HECO RT-1	R. A. Alm
TESTIMONY	Policy Statement
HECO RT-10A	L. T. Unemori
TESTIMONY	Customer Service Expense (Informational Advertising Expense)
HECO-R-10A00	Educational Background and Experience
HECO-R-10A01	Ward Research – RCEA Program Evaluation
HECO RT-19	R. A. Morin
TESTIMONY	Rate of Return on Common Equity
HECO RT-20	T. S. Y. Sekimura
TESTIMONY	Rate of Return on Rate Base
HECO-R-2001	Composite Embedded Cost of Capital, Test Year 2009 Average
HECO-R-2002	Short-Term Borrowings, Test Year 2009 Average
HECO-R-2003	Embedded Cost of Long-Term Debt, Test Year 2009 Average
HECO-R-2004	Embedded Cost of Preferred Stock, Test Year 2009 Average
HECO-R-2005	Common Equity, Test Year 2009 Average
HECO-R-2006	Sources and Applications of Funds, 2008-2009
HECO-R-2007	Summary of Financial Ratios, Test Year 2009
HECO-R-2008	Standard & Poor's: *Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings*, dated March 19*, 2009

HECO RT-21	S. M. Fetter
TESTIMONY	Financial Integrity
HECO-R-2101	Summary of ROEs in Electric Utility Rate Cases Decided in 2009

HECO RT-23	T. S. Y. Sekimura
TESTIMONY	Results of Operations, including Revenue Requirements, Rate Increase Implementation, and Summary
HECO-R-2301	Results of Operations in 2009, at Current Effective Rates, 11.00% ROE
HECO-R-2302	Results of Operations in 2009, at Current Effective Rates, 11.00% ROE without Informational Advertising
HECO-R-2303	Results of Operations in 2009,at Current Effective Rates, 11.25% ROE
HECO-R-2304	Results of Operations in 2009, at Current Effective Rates, 11.25% ROE without Informational Advertising

REBUTTAL TESTIMONY OF
ROBERT A. ALM

EXECUTIVE VICE PRESIDENT

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Policy Statement

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert A. Alm and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Executive Vice President for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company").

Q. Please describe what you will be covering in your rebuttal testimony.

A. My rebuttal testimony will first state the Company's rebuttal position in this proceeding. It will then summarize the changes that have occurred since the Company filed its 2009 test year rate case application, direct testimonies and exhibits. I will also summarize and explain the key elements of the settlement agreement that Hawaiian Electric, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and the Department of Defense ("DOD") (collectively, the "Parties") filed on May 15, 2009. I will then explain at the policy level the Company's position on the two remaining issues in this proceeding that have not been settled (i.e., informational advertising and return on common equity), and explain why the Company's proposals in these two areas are reasonable and warrant Commission approval.

Q. Will all of the witnesses who filed direct testimony for Hawaiian Electric in this proceeding also file rebuttal testimony?

A. No. The Company is filing rebuttal testimony only for issues that have not been settled and for areas that are closely associated with those issues. They are as follows:

Rebuttal #	Subject	Witness
HECO RT-10A	Informational Advertising Expense	Lynne T. Unemori
HECO RT-19	Rate of Return on Common Equity	Dr. Roger A. Morin
HECO RT-20	Rate of Return on Rate Base	Tayne S. Y. Sekimura
HECO RT-21	Financial Integrity	Steven M. Fetter
HECO RT-23	Results of Operations	Tayne S. Y. Sekimura

Q. Are any of the witnesses who filed direct testimony no longer available to testify in this proceeding?

A. Yes. Mr. William A. Bonnet who submitted HECO T-23 on the Results of Operations has since retired from the Company. Ms. Tayne S. Y. Sekimura is adopting his direct testimony and submitting rebuttal testimony (HECO RT-23) on the Results of Operations.

HAWAIIAN ELECTRIC'S REBUTTAL POSITION

Q. Did the Parties in this proceeding execute a settlement agreement on Hawaiian Electric's rate case proposal?

A. Yes. The Parties filed a Stipulated Settlement Letter on May 15, 2009. I incorporate by reference the stipulated settlement letter as an exhibit to this rebuttal testimony. The Parties agreed that the amount of the interim rate increase to which Hawaiian Electric is probably entitled under §269-16(d) of the Hawaii Revised Statutes ("HRS") is $79,820,000 or 6.16% over revenues at current effective rates.[1] In accordance with the procedural schedule approved by the Commission in this proceeding, the Company filed a Statement of Probable Entitlement on May 18, 2009, which requested the Commission to expeditiously render an Interim Decision and Order for this proceeding for an interim rate increase of $79,811,000. The proposed interim increase amount of $79,811,000 included in Exhibit 1 to the Statement of Probable Entitlement is lower by $9,000 than the $79,820,000 amount in the Stipulated Settlement Letter due to finalization of the revenue requirement run. The agreed-upon interim rate increase was based on a return on common equity of 10.5% and a rate of return on rate base of 8.45%.[2]

Q. Were there any issues on which the Parties were not able to settle?

A. Yes. The Parties were not able to settle on the following issues: (1) the appropriate test year non-labor expense for informational advertising; and (2) the appropriate return on common equity for the test year. The Parties agreed that these issues should be addressed in an evidentiary hearing.

Q. What is Hawaiian Electric's rebuttal position?

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[1] Revenues at current effective rates are revenues from base rates, revenues from the energy cost adjustment clause and revenues from the interim rate increase that went into effect on November 1, 2008 in HECO's 2007 test year rate case, Docket No. 2006-0386.

[2] The Parties also agreed that the final rates set in Docket No. 2006-0386 may impact revenues at current effective rates and at present rates, and that the amount of the stipulated interim rate increase should be adjusted when the final rates are set to take into account any such changes. Upon issuance of a final decision and order for HECO's 2007 test year rate case (Docket No. 2006-0386), the Company will report to the Commission whether any adjustment to the interim rate increase for Docket No. 2008-0083 would be necessary.

A. Hawaiian Electric's rebuttal position is that the Commission should approve a test year non-labor expense of $1,116,000 for informational advertising and a return on common equity of 11.0% for the test year in its final decision and order in this proceeding. Approval of the Company's position on these two issues would result in a revenue increase of $86,779,000 or 6.7% over current effective rates and a revenue requirement of $1,383,153,000 for the 2009 test year (HECO-RT-2301). Based on a return on common equity of 11.00%, the return on average rate base would be 8.73%.

The Company's expert witness on the return on common equity recommended a range of 11.00% to 11.25% for Hawaiian Electric's 2009 test year (HECO RT-19). To be conservative, the Company selected an 11.00% return on equity for its rebuttal position (HECO RT-20).

The 11.0% return on common equity assumes Commission approval of the revenue adjustment mechanism ("RAM") proposed in the decoupling proceeding (Docket No. 2008-0274). As explained by Dr. Roger Morin in HECO RT-19, if the Commission rejects the Company's RAM proposal, the return on common equity should be increased by 25 basis points to 11.25% due to the increased risk that the Company would be exposed to without the RAM.

Q. What would be the revenue increase over revenues at current effective rates and the revenue requirement at an 11.25% return on common equity?

A. At an 11.25% return on common equity, the revenue increase would be $89,841,000 or 6.9% over revenues at current effective rates and the revenue requirement would be $1,386,215,000. Based on an 11.25% return on common equity, the return on average rate base would be 8.87% (HECO-R-2303).

Q. What is the revenue requirement value of the non-labor informational advertising expense at issue in this proceeding?

A. The Consumer Advocate proposed a reduction of $774,000 from the Company's proposed $1,116,000 of non-labor informational advertising expense in the test year (CA-101, Schedule C-21). At a return on common equity of 11.0%, the revenue requirement value of the $774,000 adjustment is $848,000.

<u>Implementation of Rate Increase</u>

Q. How is Hawaiian Electric requesting that the revenue increase in this proceeding be granted?

A. Hawaiian Electric requests that the Commission grant the increase and revisions to its rate schedules in two steps:

1) An interim rate increase of $79,811,000 as specified in the Statement of Probable Entitlement filed by Hawaiian Electric on May 18, 2009 and in accordance with HRS §269-16(d). The Company respectfully requests the Commission to also approve the Revenue Balancing Account ("RBA") Provision tariff (provided in HECO T-22 Attachment 1 of the Stipulated Settlement Letter filed on May 15, 2009 and Exhibit 2 of the Statement of Probable Entitlement filed on May 18, 2009), to be effective on the date of the interim decision and order.

2) A final increase when the Commission issues its final decision and order to provide for the amount of the total requested revenue increase not included in the interim rate increase. The Company respectfully requests the Commission to also approve the Purchased Power Adjustment Clause tariff (provided in Attachment 1 of the HECO T-22 Rate Case Update, pages 37-39), to be effective on the same effective date as the final rates and charges approved in this proceeding.

Q. When does Hawaiian Electric propose that the Commission grant the interim rate increase?

A. Hawaiian Electric proposes that the Commission issue an order granting an interim rate increase by July 2, 2009, in accordance with the procedural schedule in its *Order Amending Stipulated Procedural Order*, issued on January 21, 2009. From a financial standpoint, it is important to the Company for the Commission to issue the interim decision and order at that time since any rate relief will at most apply to half of the test year.

Q. How does Hawaiian Electric propose to implement the interim and final rate increases?

A. Hawaiian Electric proposes to implement the interim and final rate increases in accordance with the Stipulated Settlement Letter filed on May 15, 2009. See Stipulated Settlement Letter, Exhibit 1, pages 84-87, HECO T-22 Attachment 2.

APPLICATION AND DIRECT TESTIMONY

Q. When did Hawaiian Electric file its application, direct testimonies, exhibits and workpapers in this proceeding?

A. Hawaiian Electric filed its application, direct testimonies, exhibits and workpapers for its 2009 test year rate case on July 3, 2008.

Q. Please summarize the key elements of Hawaiian Electric's rate case application.

A. Hawaiian Electric requested a revenue increase of $97,011,000 (based on April 2008 fuel oil prices), or 5.2%, over revenues at current effective rates for a normalized 2009 test year. The proposed revenue increase was based on return on common equity of 11.25%. The Company stated that the rate case is primarily driven by the need for the following:

1) The costs of adding the new facilities, including the new biofueled generating unit, the Campbell Industrial Park Combustion Turbine Unit 1 ("CT-1 CIP") scheduled for July 2009, necessary to meet Hawaiian Electric's obligation to provide adequate and reliable service to its customers;
2) The higher costs of operating and maintaining Hawaiian Electric's existing utility infrastructure; and
3) The need to maintain the Company's financial integrity.

Hawaiian Electric requested the revenue increase in three steps:

Step Increase	Amount ($1,000)	Effective Date
1) Interim Increase	$73,064	On or before May 1, 2009
2) CIP CT-1 Step Increase	$23,947	At the in-service date of CIP CT-1 (scheduled for July 31, 2009)
3) General Increase	Balance	Final Decision and Order
Total Rate Increase	$97,011	

The purpose of the CIP CT-1 Step Increase was to enable the Company to recover the full cost of the CIP CT-1 after the generating unit went into service. Hawaiian Electric estimated the amount of the CIP CT-1 Step to be $23,947,000 on an annual basis.

Q. Why did Hawaiian Electric propose a step increase for the CIP CT-1 generating unit?

A. There were a number of important reasons for proposing the CIP CT-1 Step Increase. First, Hawaiian Electric will incur substantial costs for the CIP CT-1 generating unit, and proposed that it should be allowed to recover the full amount of the costs it incurs for CIP CT-1 as soon as it begins incurring the costs. The use of a step increase would also ensure that customers would not have to pay for the costs of CIP CT-1 until Hawaiian Electric begins incurring such costs. The Company stated that the use of a step increase would better time the revenue increase to match the cost increase that necessitates the proposed step increase. As I explained in my direct testimony, the

Commission had approved step increases in prior rate cases (HECO T-1, pages 15-19).

Q. Did Hawaiian Electric propose any alternatives to the CIP CT-1 Step Increase?

A. Yes. The Company stated that if the Commission rejects the CIP CT-1 Step Increase, it should approve an interim increase of $85,189,000 as shown on HECO-2303 rather than $73,064,000. The interim increase of $85,189,000 (referred to as "Base Case" in the Company's testimonies in this proceeding) included the 2009 CIP CT-1 plant additions (net of deferred income taxes) in the end of test year rate base balance but not in the beginning of test year rate base balance (HECO T-1, page 7).

Q. Did the Commission hold a public hearing for this rate case?

A. Yes. The Commission held a public hearing on September 18, 2008 at its hearing room.

Q. Did the Consumer Advocate and the Department of Defense conduct discovery on the Company's application and testimonies in this proceeding?

A. Yes. The Consumer Advocate and the Department of Defense conducted extensive discovery on the Company's rate case filings. The discovery period began when the Consumer Advocate submitted its first information requests on July 7, 2008, and ended when the Company submitted its last responses to information requests on April 3, 2009. The Consumer Advocate issued 504 information requests and the DOD issued 133. Because the information requests frequently had subparts, the total number of questions was much higher than the 637 information requests that the Consumer Advocate and the DOD submitted.

Q. Subsequent to the filing of the Company's application, were there occurrences that impacted the Company's rate request in this proceeding?

A. Yes. There were two major occurrences that impacted and ultimately warranted certain significant changes to the Company's rate request. The first was the execution of the *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* ("Energy Agreement"). The second was a reduction to the Company's sales forecast, caused in large part by the economic downturn. I will discuss each of these in the sections below.

ENERGY AGREEMENT

State Energy Policy and the Energy Agreement

Q. What did your direct testimony cover with respect to the efforts of the Hawaiian Electric Companies to facilitate and accelerate the development of renewable resources, while maintaining its financial integrity and credit standing?[3]

A. In my direct testimony, I pointed out that the world is rapidly changing with respect to how it looks to meet its future energy demand, and Hawaii is at the forefront of that effort. Traditional fossil fuel electrical generation is giving

[3] The Hawaiian Electric Companies are Hawaiian Electric, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO").

way to renewable energy and other pathways to control energy use, driven by rapidly rising fuel oil prices, and international, national and state-by-state initiatives to reduce greenhouse gas ("GHG") emissions and to increase the use of renewable energy and energy efficiency resources. Hawaiian Electric recognizes its obligation to facilitate and accelerate the development of these renewable resources, not only because of the challenge to achieve the requirements under the Renewable Portfolio Standards ("RPS") law, but even more importantly to further our State's goal of energy independence.

To do this, I pointed out that we have to do two things well - keep the current system providing reliable power to businesses and residences alike, and transition the system to one that focuses on renewable energy, energy efficiency, and energy conservation. In order to continue to provide reliable and adequate service, we have to operate, maintain and enhance our core utility infrastructure – including the aging generating units that still generate most of the electricity used by our customers, and the aging transmission and distribution systems that deliver the electricity to our customers. To facilitate achievement of the State's energy goals, we have to support and help accelerate Hawaii's transition to a clean and sustainable energy future. To accomplish either task means that we have to maintain our financial integrity and credit standing.

Q. Fast forward to today. Just how rapidly is the world changing?

A. In January, the State of Hawaii and United States Department of Energy ("DOE") signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative ("HCEI").

Last summer, world oil prices peaked at over $140/barrel, before plummeting in the face of a world-wide economic crash – showing just how volatile oil prices can be.

On October 20, 2008, the Governor of the State of Hawaii, the State of Hawaii Department of Business, Economic Development and Tourism ("DBEDT"), and the Consumer Advocate and the Hawaiian Electric Companies executed the landmark Energy Agreement. The Energy Agreement acknowledges that the signatories of the agreement must "move more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency."

The Energy Agreement provides that the Energy Agreement Parties will pursue a wide range of actions with the purpose of decreasing the State of Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation.

The Energy Agreement commits Hawaiian Electric to facilitate the integration of substantial amounts of clean, renewable energy (wind energy in particular) into its grid and to enable electricity consumers to manage their electricity use more effectively. The agreement explicitly provides for the

Energy Agreement Parties to seek amendment to the Hawaii RPS law (law which establishes renewable energy requirements for electric utilities that sell electricity for consumption in the State) to increase the current requirements from 20% to 25% by the year 2020, and to add a further RPS goal of 40% by the year 2030. The revised RPS law would also require that after 2014 the RPS goal be met solely with renewable energy generation versus including energy savings from energy efficiency measures. However, energy savings from energy efficiency measures would be counted toward the achievement of the overall HCEI 70% goal.

The Energy Agreement also discusses and documents a number of initiatives and renewable energy projects that will assist in achieving the State's goal of promoting and increasing the use and development of renewable energy resources. These programs and projects include but are not limited to a competitive request for proposal for 100 MW of non-firm renewable energy on Oahu, small, medium and large wind projects on all islands which could total nearly 500 MW, waste-to-energy projects in the range of 30 MW, ocean thermal projects (potentially up to 100 MW), the increased use of biofuels where appropriate, proposed solar, biomass, wave and geothermal projects in the range of 40 MW and development of both a Photovoltaic ("PV") Host program and a feed-in tariff ("FIT") program.

Finally, while memorializing the commitment by the signatories to support the acceleration to a much more renewable, distributed and intermittent-powered system with a smart grid, the signatories also recognized the "need to assure that Hawaii preserves a stable electric grid to minimize disruption to service quality and reliability. In addition, we recognize the need for a financially sound electric utility. Both are vital components for our achievement of an independent renewable energy future."

Q. What are the key components of the Energy Agreement?

A. The four key elements of the Hawaii Energy Policy reflected in the Energy Agreement are (1) fixed-price indigenous renewable energy resources, (2) energy efficiency and conservation, (3) biofueling, and (4) incentive realignment.

Q. Does the Energy Agreement represent a new energy policy for Hawaii?

A. It <u>does not</u> represent a new direction. Hawaii energy policy strongly supports: (1) Increased energy self-sufficiency; (2) Greater energy security in the face of threats to Hawaii's energy supplies and systems; and (3) Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use; as well as (4) Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people.

It <u>does</u> represent a substantial commitment to strongly accelerate the pace at which the first three objectives are obtained.

And, in large measure, the Energy Agreement resulted from the Governor's strong desire to formalize the key elements of Hawaii's energy policy in one document. Much of what is included in the Hawaii Clean Energy Initiative was begun prior to that formulization.

Q. Are the initiatives referred to in the agreement all new commitments?

A. No. The Energy Agreement includes references to much of the Hawaiian Electric Companies' on-going renewable energy and energy efficiency efforts (such as the Renewable Energy RFP), as well as <u>new</u> commitments made by the Companies in the Agreement. Many of the on-going efforts were initiated under the auspices of Commission polices. The Energy Agreement was used as a platform to reflect existing decisions, agreements and programs, as well as to document new commitments by the parties. The value of the Energy Agreement is its potential to accelerate Hawaii's transition away from oil – to a future based on energy security and stability.

Q. What will it take to achieve the objectives of the Hawaii Clean Energy Initiative, which include meeting 70% of Hawaii's "business as usual" energy needs in the ground transportation and energy utility sectors through clean energy resources by 2030?

A. It will take the combined efforts of all stakeholders. The Energy Agreement is not self-effectuating. The electric utilities, the Consumer Advocate, the State Administration, the Hawaii State Legislature and the Commission all have to do their part.

Q. What has happened during the 2009 legislative session?

A. The Legislature has done its part to embed the commitments in the Energy Agreement into State law and policy. H.B. No. 1464 H.D. 3 S.D. 2 C.D. 1 (the "HB 1464") will add to or amend various portions of the Hawaii Revised Statutes ("HRS") related to clean energy. The bill states that: "Attaining independence from Hawaii's detrimental reliance on fossil fuels has been a longstanding objective for the State." "Hawaii is the state most dependent on petroleum for its energy needs. It pays the highest electricity prices in the United States, and its gasoline costs are among the highest in the country." As a result, "Reducing our oil dependence and the consequent price volatility and attaining energy security are critical."

The bill specifically refers to the HCEI: "On January 28, 2008, the signing of a memorandum of understanding between the State of Hawaii and the United States Department of Energy launched the Hawaii clean energy initiative." "This effort presents a range of measures to reach aggressive energy goals while balancing the interests of various stakeholders." "The purpose of this Act is to provide a first step in aligning Hawaii's energy policy laws with the State's energy goals." In particular:

(1) The Bill increases the electric utilities' 2020 RPS requirement from 20% to 25%, and adds a new 40% requirement for the year 2030. Prior to January 1, 2015, at least 50% of a utility's RPS must be met by "electrical generation using renewable energy as the source". After January 1, 2015, however, a utility's entire RPS will need to be met by renewable generation, and "electrical energy savings" will no longer count toward RPS requirements.

(2) Part VI of the Bill directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy-efficiency programs and technologies." In particular, the Act requires that the EEPS be designed to achieve 4,300 GWh of

electricity use reductions statewide by 2030, with interim Commission-established goals for 2015, 2020, and 2025. The Commission "may also adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies.

(3) Part III of the bill adds six new powers and duties to those of the State's Energy Resources Coordinator.

(4) Part V establishes, within DBEDT, a Hawaii clean energy initiative program to manage the State's transition to a clean energy economy.

The Legislature also approved H.B. No. 1270, H.D. 1, S.D.2, which was signed into law (as Act 50) on May 6, 2009. Act 50 makes it clear that the pricing of renewable resources is to be delinked from the oil-based prices of fossil-fuel resources.

In addition, it is significant that the State Legislature had already taken actions to facilitate the permitting of big wind projects on the Neighbor Islands, and to promote and encourage the use of biofuels.

Q. What had been done to promote big wind projects?

A. Signed into law on July 1, 2008, Act 207 (2008) was enacted to establish a renewable energy facility siting process for state and county permits required for siting, development, construction, and operation of a new renewable energy facility with a capacity of at least 200 MW.

Q. How do biofuels fit into the picture?

A. Biofuels are a critical component of a "green" energy future, because they can be used to generate energy from conventional generators, which provide essential grid services, including load following, frequency response, voltage control and on-line operating and spinning reserves. In 2006 and 2007, the Legislature enacted Act 196 (2006), which addresses the use of biofuels in vehicles, Act 162 (2006), which amended the RPS law to add a definition of biofuels, Act 240 (2006), which provided specific support for biofuel research and a specific biofuel preference, Act 159 (2007), which has the stated purpose to encourage further production and use of biofuels in Hawaii, and Act 253 (2007) requires the Hawaii Department of Business, Economic Development, and Tourism to develop and prepare a bioenergy master plan.

Q. What is the role of the Commission?

A. The Commission has its traditional role of implementing policies enacted by the legislature. But the Commission also has its equally important role of formulating the policies necessary to achieve the State energy objectives.

Over the years, the Commission has taken a major, proactive role in encouraging and accelerating the use of renewable energy and clean energy resources in the State of Hawaii; and has approved the use of regulatory cost recovery and incentive alignment mechanisms to facilitate that process.

In 1990, the Commission initiated a proceeding to require energy utilities to implement an Integrated Resource Planning ("IRP") process. See Order No. 10458, issued January 10, 1990 in Docket No. 6617. The Commission's Framework for Integrated Resource Planning ("IRP Framework") formally required energy utilities to consider demand-side management ("DSM") resources in this planning process, and provided for DSM cost recovery and incentive mechanisms. See IRP Framework (May 22, 1992), adopted by Decision and Order No. 11523 (March 12, 1992), as modified by Decision and Order No. 11630 (May 22, 1992).

In 1994, the Commission initiated a proceeding to identify the policies, programs, procedures, and incentives necessary for the successful deployment of renewable technologies, such as wind power, biomass, solar, hydro and geothermal in Hawaii. One of the stated purposes of the investigation was to formulate strategies for the removal of barriers and for the development and utilization of renewable energy resources in Hawaii. See Order No. 1344, issued August 11, 1994 in Docket No. 94-0226.

In 2003, the Commission initiated a proceeding to investigate distributed generation ("DG") in Hawaii. See Order No. 20582, issued October 21, 2003, and Decision and Order No. 22248 issued January 27, 2006, as clarified by Order No. 22375, issued April 6, 2006, in Docket No. 03-0371.

In 2004 and 2005, the Commission held workshops to examine incentive mechanisms to encourage the accomplishment of Hawaii's Renewable Portfolio Standards ("RPS").

In 2005, the Commission initiated the Energy Efficiency Docket to examine energy efficiency goals and the market structure for DSM programs, as well Hawaiian Electric's proposals for new DSM proposals. See Order No. 21698, issued March 16, 2005, and Decision and Order No. 23258, issued

February 13, 2007, as modified by Order No. 23448, issued May 21, 2007, in Docket Nos. 04-0113 and 05-0069.

In 2006, the Commission initiated a proceeding pursuant to Act 162 (2006) to establish an RPS penalty framework. See Order No. 23191, issued January 11, 2007, Decision and Order No. 23912, issued December 20, 2007 ("D&O 23912"), and Order Relating to RPS Penalties, issued December 19, 2008, in Docket No. 2007-0008. By Order No. 23913, also filed December 20, 2007 ("Order 23913"), and in accordance with D&O 23912, the Commission opened a new docket, Docket No. 2007-0416 (the "REIP Docket"), for the examination of the Companies' proposed Renewable Energy Infrastructure Program.

At the end of last year, the Commission initiated proceedings on decoupling and feed-in tariffs. See Orders Initiating Investigation, issued October 24, 2008 in Docket Nos. 2008-0273 and 2008-0274.

Q. The cost of capital witnesses for the other Parties have taken the position that incentive mechanisms in the Energy Agreement - decoupling, the power purchase adjustment clause and the clean energy infrastructure surcharge - lower the Company's operating risk and thus, its required rate of return on common equity. What is Hawaiian Electric's position?

A. As Dr. Morin states in HECO RT-19, while adjustment clauses and cost tracking mechanisms are beneficial in mitigating operating risk, the approval of adjustment clauses and cost recovery mechanisms by regulatory commissions is widespread in the utility business and, in Hawaiian Electric's case, there are other significant factors to consider that work in the reverse direction for Hawaiian Electric. These factors are discussed earlier in my testimony, as well as in Ms. Sekimura's rebuttal testimony, HECO RT-20.

Based on the results of his analyses, the application of professional judgment, the risk circumstances of Hawaiian Electric, and the unsettled current market environment, Dr. Morin's opinion is that a conservative just and reasonable return on the common equity capital of Hawaiian Electric's electric utility business is in a range of 11.00% - 11.25%, assuming approval of a revenue adjustment mechanism as proposed in the joint decoupling proposal filed by the Company and the Division of Consumer Advocacy in the decoupling proceeding (Docket No. 2008-0274), and in a range of 11.25% - 11.50% without decoupling. The Company has used the low end of the 11.00% - 11.25% range in calculating its rebuttal revenue requirements. This is discussed further later in my testimony.

<u>Operating Risks of the Energy Agreement</u>

Q. As discussed above, the Energy Agreement calls for a wide array of measures to move Hawaii decisively and irreversibly away from imported fossil fuel and towards indigenously produced renewable energy and an ethic of energy efficiency. What does the Energy Agreement say about impacts on the utility?

A. The Energy Agreement commits the Hawaiian Electric Companies to integrate substantial amounts of renewable energy into their grids, including 400 megawatts ("MW") of wind power generated on Molokai and/or Lanai and transmitted via undersea cable to Oahu. The agreement recognized that such measures would increase the operating risks of the Hawaiian Electric Companies, which may potentially affect customers, and therefore acknowledged that there is a need to assure that Hawaii preserves a stable electric grid to minimize disruption to service quality and reliability and to have a financially sound electric utility (Energy Agreement, page 1).

Q. What is the time frame for implementation of the Energy Agreement measures?

A. The Energy Agreement called for implementation of these measures on an expedited basis. Completion dates and milestones were specified throughout the agreement and in Exhibits A and B to the agreement. For example, Exhibit B to the agreement specified a milestone of first quarter 2010 for the initiation of studies that would assess the integration of the Molokai/Lanai wind power onto Oahu's grid (known as the "Big Wind Studies"). In order to meet the goals set forth by the Energy Agreement, and the much higher RPS enacted by the Legislature as contemplated by the Energy Agreement, it is necessary for the Hawaiian Electric Companies, and Hawaiian Electric in particular, to begin incurring costs to implement the Energy Agreement measures now.

Q. How do the Energy Agreement measures increase the Company's operating risk?

A. The Energy Agreement will put Hawaii at the forefront of renewable energy implementation. However, there will be uncertainty as to the impact on reliability and service quality of integrating such high levels of as-available renewable energy onto the Company's grid and what it would take financially to achieve successful integration.

Attachment 1 of the HECO T-20 Rate Case Update provided a November 26, 2008 credit profile issued by Standard & Poor's ("S&P") that discussed the risks of the Energy Agreement. S&P's credit concerns focused on three areas: the feasibility of the plan and what the ramifications are for Hawaiian Electric if it cannot meet the ambitious program outlined in the agreement, the costs of the program and whether ratepayers would ultimately be willing to bear them, and the potential impact on reliability. S&P pointed out that electric system reliability would be a major credit consideration going forward as the issues presented by integrating substantial intermittent solar, wind and distributed generation resources are not trivial. The profile concluded that the next few years are likely to be pivotal for Company credit quality as the Energy Agreement details will likely shape the Company's financial position for years to come.

Q. Does the Energy Agreement attempt to mitigate these risks?

A. Yes. The Energy Agreement attempts to balance the risks of integrating large amounts of renewable energy into the grid with certain recovery mechanisms that would enable the utilities to timely recover operating costs and capital investment and maintain their financial integrity. A financially strong utility is essential to the Energy Agreement's success since the utility would need to provide the infrastructure to transmit the renewable energy from the provider to the consumer and the ability of the renewable energy providers to obtain financing for their projects largely depends on the financial viability of the utility. Third-party project developers are able to finance their projects based on their purchased power agreements with credit-worthy purchasers – the electric utilities. Thus, degradation of the utility's credit quality would also be detrimental to third-party developers of renewable energy projects. (See Reply Position Statement, Docket No. 2007-0416, pages 32-33.)

Q. What recovery mechanisms does the Energy Agreement call for?

A. The Energy Agreement calls for the establishment of a revenue decoupling mechanism (which would include decoupling sales from revenues, using a revenue balancing account ("RBA") and a revenue adjustment mechanism ("RAM") to allow rates to be adjusted between rate cases in order to reflect increases in O&M costs and rate base, a purchased power adjustment clause and the Renewable Energy Infrastructure Program/Clean Energy Infrastructure ("REIP/CEI") Surcharge.

Q. Has the Company filed proposals for these recovery mechanisms with the Commission?

A. Yes. In this proceeding, the Company proposed an RBA that would go into effect upon issuance of the interim decision and order for this proceeding (Rate Case Update, HECO T-1, page 9). HECO T-22 Attachment 1 of the Stipulated Settlement Letter filed on May 15, 2009 and Exhibit 2 of the Statement of Probable Entitlement filed on May 18, 2009 provide a proposed RBA tariff.

In Docket No. 2008-0274, the Hawaiian Electric Companies and the Consumer Advocate filed a joint proposal for approval of a RAM.

In this proceeding, the Company proposed a purchased power adjustment clause in the HECO T-22 Rate Case Update (page 2).

In Docket No. 2007-0416, the parties in that proceeding filed a stipulation on October 22, 2008 that recommended approval of the REIP and the related REIP/CEI Surcharge.

Sales Decoupling

Q. On October 24, 2008, the Commission initiated Docket No. 2008-0274 ("Decoupling docket") to investigate the implementation of a decoupling mechanism for the Hawaiian Electric Companies, and directed the Hawaiian Electric Companies and the Consumer Advocate to file a joint decoupling proposal.

What is the Hawaiian Electric Companies' and the Consumer Advocate's joint decoupling proposal in the Decoupling docket?

A. The Joint Decoupling Proposal filed in the "Joint Final Statement of Position of The HECO Companies and Consumer Advocate" on May 11, 2009, includes a sales decoupling mechanism, which will be implemented through a Revenue Balancing Account ("RBA"), and a Revenue Adjustment Mechanism ("RAM"). The purpose of the sales decoupling mechanism is to remove the linkage between utility sales and revenues, in order to encourage energy efficiency. The purpose of the RAM is to adjust revenues decoupled from sales to reflect changes in revenue requirements between rate cases. In the Decoupling docket, the proposed RBA also includes provisions that implement the RAM for the periods between rate cases, which is different from the RBA that is proposed in the instant proceeding.

Q. What is the Company's decoupling proposal in this proceeding?

A. In our Rate Case Update, the Company proposed that a sales decoupling mechanism be made effective upon issuance of an interim decision and order in this rate case. We also submitted a proposed tariff in the response to CA-IR-277 that would establish an RBA tariff effective on the date of the interim decision and order. HECO T-22 Attachment 1, which is attached to the Stipulated Settlement Letter, is a revision to the RBA tariff to conform with the agreements reached between the Consumer Advocate and the Hawaiian Electric Companies in the Joint Final Statement of Position of the HECO Companies and the Consumer Advocate. This would implement the provision in paragraph 1 of Section 28 of the Energy Agreement which states: "The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Company Rate Case (most likely in the summer of 2009)."

The Consumer Advocate agreed in the decoupling proceeding (Docket No. 2008-0274) that "the initial sales decoupling mechanism would begin with the establishment of Authorized Base Revenues, which would be equal to the revenue requirements approved by the Commission in its interim decision and orders for HECO's 2009 test year general rate case proceeding and MECO's and HELCO's 2009 or 2010 test year general rate case proceedings." See Joint

Final Statement of Position of the HECO Companies and Consumer Advocate, page 11.

The Company is not proposing that the RAM included in the Joint Decoupling Proposal be made effective until the Commission approves a RAM in the decoupling docket.

Q. Why is there a difference between the RBA proposed in the Decoupling docket and the RBA proposed in this proceeding?

A. In this proceeding the Company is only requesting the approval and implementation of the RBA, which will effectuate sales decoupling with the Commission's issuance of the interim order. The Company is not requesting the implementation of the RAM in this proceeding. As a result, the RBA that is submitted for approval in this proceeding has had all references to the RAM removed. The RBA approved in this rate case will be an "interim" RBA since it will be changed to conform to the RBA approved by the Commission when it issues its order in the Decoupling docket. I discuss the RBA and the RAM in greater detail below.

Q. Why is it important that decoupling be implemented?

A. The implementation of decoupling is important because it eliminates one of the main disincentives that utilities currently have to facilitate demand-side management ("DSM"), customer-sited distributed generation ("DG"), and distributed energy storage. Under the traditional regulatory model, if effective DSM and renewable DG are promoted, customer sales are lowered which hurts the Company financially since it receives the bulk of its revenues from the sales of kWh. As stated on page 9 of the scoping paper issued in the Decoupling docket, "Decoupling Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission", which was prepared by the Commission's consultant, the National Regulatory Research Institute, "If the regulator's objective is to encourage the use of renewable resources, decoupling is necessary to eliminate the disincentive of sales losses associated with renewable resources."

Q. If the Company's revenues are not linked to the sale of kWh, what will determine the Company's revenues?

A. With decoupling, the Company's revenues authorized by the Commission become the Company's target revenue. For instance, the target revenue for 2009 will be the test year revenue requirement approved by the Commission in the instant proceeding. So, in 2009, when the interim order is issued by the Commission and with its approval of the RBA, the Company's target revenue for the months remaining in the test year will be prorated based on the amount of 2009 revenue authorized by the Commission.

Q. What role does the RBA play in this process?

A. Very simply, the purpose of the RBA is to record the difference between the base revenue amount that the Company records (with certain adjustments) and the amount of the Company's target revenue. Its purpose is also to record the monthly interest on the simple average of the beginning and ending month balances in the RBA. At the end of the calendar year, the Company's revenue will be no lower or higher than the target revenue amount. If there is an over collection of recorded revenue as compared to the target revenue, the Company will refund the over collection to its customers with interest in the following year, and if there is an under collection, the Company will collect the amount under collected in the following year with interest. The over or under collection will have been reflected as the year-end balance in the RBA.

Q. How will the RBA be implemented?

A. The RBA is proposed to be implemented through a tariff. As stated above, Hawaiian Electric submitted a revised proposed tariff, "Revenue Balancing Account ('RBA') Provision", as HECO T-22, Attachment 1, to Exhibit 1 to the Settlement Letter filed on May 15, 2009, which was agreed to by all the parties in this proceeding. HECO T-22, Attachment 1, was also attached to the Company's Statement of Probable Entitlement, filed on May 18, 2009.

Q. Is it necessary for the Commission to approve the RBA Provision in the decoupling docket, before it is implemented on an interim basis in this rate case?

A. No. The RBA Provision will be further reviewed by the Commission in the Decoupling docket. The RBA Provision approved in this proceeding will be conformed to the sales decoupling mechanism ultimately approved by the Commission in the Decoupling docket. The approval of the RBA Provision by the Commission in the instant proceeding on an interim basis will allow the first step in implementing the decoupling process to take place as quickly as possible.

There are three reasons why the RBA should be implemented on an interim basis when the Commission issues its interim order:

1) It is appropriate for sales decoupling to begin with the implementation of the new rates that incorporate the Company's reduced and most current sales forecast. Therefore, it is appropriate that the Energy Agreement recognized that sales decoupling should begin with the Commission's interim decision in this rate case (see Energy Agreement, page 33);
2) It is important that the Company's revenues be decoupled from sales with the transfer of energy efficiency programs to the third party administrator;
3) There is still a great deal of uncertainty regarding the Company's future sales. By authorizing the establishment and implementation of the RBA for sales decoupling, there will be more certainty in terms of the Company's revenues, which may reduce concerns regarding the Company's credit quality as discussed above.

Q. Are the parties in the Decoupling docket in agreement that the Company's revenues should be decoupled from sales of kWh?

A. It appears that all the parties in the Decoupling docket are in agreement that sales decoupling should be implemented.

Q. What about the parties in the instant proceeding? Do they support the approval and implementation of the RBA Provision?

A. As memorialized in the Exhibit 1 of the Settlement Letter filed by the Consumer Advocate, Department of Defense, and the Company on May 15, 2009, all parties agreed that the Commission should allow Hawaiian Electric to establish the RBA Provision to be effective on the date of the interim decision and order in this proceeding.

Q. What is the purpose of the RAM in the decoupling process?

A. The purpose of the RAM is to adjust revenues decoupled from sales to reflect changes in revenue requirements between rate cases related to increases in cost due, for example, to inflation and to continued investment in infrastructure necessary to maintain service reliability. The Company and the Consumer Advocate propose to implement the RAM through a tariff, the "Rate Adjustment Mechanism Provision". A proposed draft of the RAM tariff was filed as Exhibit B in the "Joint Proposal on Decoupling and Statement of Position of the HECO Companies and the Consumer Advocate", on March 30, 2009, in the Decoupling docket. It was revised and also filed in the Decoupling docket as Exhibit B in the "Joint Final Statement of Position of the Hawaiian Electric Companies and Consumer Advocate" on May 11, 2009.

Q. Is the Company asking the Commission to approve the RAM provision at this time?

A. No. As stated above, there is no proposal to implement the RAM at this time. The RAM would not be implemented until the Commission concludes its review and approval process in the Decoupling docket. The base rates set by the Commission in this proceeding would establish the baseline rates to which the RAM would be applied.

Purchased Power Adjustment Clause

Q. What does the Energy Agreement say about the purchased power adjustment ("PPA") clause?

A. Section 30 of the Energy Agreement includes the following provision:

- The Hawaiian Electric Companies will be allowed to pass through reasonably incurred purchase power contract costs, including all capacity, O&M and other non-energy payments approved by the Commission (including those acquired under the feed-in tariff) through a separate surcharge.
    - If approved, these costs will be moved from base rates to the new surcharge.
    - The surcharge will be adjusted monthly and reconciled quarterly.

Q. Why did Hawaiian Electric propose the purchased power adjustment clause in this proceeding?

A. Because this provision calls for the transfer of recovery of these purchased power costs from base rates to a new surcharge, it is appropriate for the Company to propose the purchased power adjustment clause in this rate case. (See Rate Case Update, HECO T-22.) The purchased power costs are largely existing costs that are already in base rates, as opposed to incremental costs of new projects that have not yet been incorporated into rates. Purchased energy costs would continue to be recovered through the Energy Cost Adjustment Clause to the extent they are not recovered through base rates. HECO did not remove any purchased power costs from the test year revenue requirement but as shown in Attachment 1, page 36 of the HECO T-22 Rate Case Update, HECO included $175,431,000 of electric sales revenues at proposed rates for recovery through the new PPA Clause in the 2009 test year.

Q. How will the purchased power adjustment clause enhance the Company's credit quality?

A. The HECO T-20 update explains that the purchased power adjustment clause will enhance the Company's financial profile to maintain Hawaiian Electric's current credit rating which in turn will enable Hawaiian Electric to support new Hawaii Clean Energy initiatives. A financially stable utility will be able to invest in new renewable resources, infrastructure to facilitate the addition of new renewable resources from independent power producers, and conversion of the existing system to renewable technologies. In addition, the Company expects to enter into numerous new purchased power agreements for renewable energy. A creditworthy off-taker helps to attract prospective independent power producers.

<u>REIP/CEI Surcharge</u>

Q. Please describe the REIP/CEI Surcharge.

A. The Hawaiian Electric Companies originally proposed the REIP Surcharge in Docket No. 2007-0008 and later in Docket No. 2007-0416 in conjunction with the Renewable Energy Infrastructure Program. The purposes of the Renewable Energy Infrastructure Program are (a) to encourage development of and investment in renewable energy infrastructure projects in order to facilitate third-party development of renewable energy resources and maintain current renewable energy resources, and (b) to enhance energy choices for customers by providing a means for the Companies to recover their investment in Renewable Energy Infrastructure Projects in a timely fashion. The surcharge was intended to recover the capital costs, deferred costs relating to software development and licenses and/or other relevant costs approved by the Commission of a Renewable Energy Infrastructure Project. The types of projects eligible for recovery through the surcharge, subject to Commission approval, include 1) infrastructure that is necessary to connect renewable energy projects, 2) projects that make it possible to accept more renewable energy and 3) projects that encourage renewable choices and/or customer control to shift or conserve their energy use.

Q. Did the Energy Agreement provide for an equivalent surcharge?

A. Yes. Section 29 of the Energy Agreement called for a Clean Energy Infrastructure ("CEI") Surcharge. On November 28, 2008, the Hawaiian Electric Companies and the Consumer Advocate filed a letter stating that they agree that the proposed REIP Surcharge is substantially similar to the CEI Surcharge included in the Energy Agreement, and the REIP Surcharge proposal satisfies the Energy Agreement provision that the implementation procedure of the CEI Surcharge recovery mechanism be submitted for Commission approval by November 30, 2008. The Hawaiian Electric Companies and the Consumer Advocate reaffirmed that the record in the REIP proceeding was complete and ready for decision- making. The Companies have since referred to the surcharge as the REIP/CEI Surcharge.

<u>Importance of Cost Recovery Mechanisms</u>

Q. How important are these regulatory initiatives to realign incentives?

A. They are essential. Hawaiian Electric cannot survive the shift in energy policy inherent in the Energy Agreement without a change in incentive alignment.

The Hawaiian Electric Companies need to be able to raise the capital to construct and install these infrastructure projects in the financial markets without degrading credit quality, or increasing the cost of capital, either of which would be detrimental to ratepayers and the development of third-party renewable energy projects. The Companies' current capital expenditure budgets are already significant given increased loads and the aging infrastructure on each system. At the same time, our credit ratings have been downgraded, and adding to our capital requirements without demonstrating support for the timely ability to earn on and recover that investment would exacerbate that situation.

Q. Is this the first recognition in Hawaii that incentives should be aligned with policies?

A. No. State and Commission energy policies strongly mandate and promote the use of Hawaii's renewable and clean energy resources, and support the use of regulatory mechanisms that align incentives with policy.

HRS §269-27.2, enacted in1977, with major amendments in 1982 (Act 266), 1988 (Act 246), 2004 (Act 95), 2006 (Act 162), 2008 (Act 207) and 2009 (Act 50), recognizes the importance of keeping the utilities whole, while encouraging renewable energy development. It provides that the Commission "may allow payments made by the public utility to nonfossil fuel producers for firm capacity and related revenue taxes to be recovered by the public utility through an interim increase in rates until the effective date of the rate change approved by the commission's final decision in the public utility's next general rate proceeding . . . ." The Hawaii Senate's Committees on Agriculture, Energy and Ocean Resources, and on Public Utilities found that, "The recovery of payments made to nonfossil fuel producers by an electric public utility will encourage the public utility to utilize the nonfossil fuel sources." See Act 246, Relating to Alternative Energy § 1, S.B. No. 2362 (1988). Agreeing with this position, the Legislature's subsequent conference committee report stated in part: "This interim rate relief would properly compensate the electric utility in a timely manner and thereby encourage their use of nonfossil fuel generated electricity." See Conf. Com. Rep. HC 32-88, in the 1988 House Journal at 772.

The RPS law also recognizes the importance of keeping the utilities whole. HRS § 269-94 provides in pertinent part that:

> The public utilities commission may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both.

The RPS law further provides in HRS § 269-95 that the Commission shall:

> (1) By December 31, 2007, develop and implement a utility ratemaking structure, which may include performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards established in section 269-92 . . . ;

> (2) Gather, review, and analyze empirical data to determine the extent to which any proposed utility ratemaking structure would impact electric utility companies' profit margins and to ensure that the electric utility companies' opportunity to earn a fair rate of return is not diminished . . . ;

In addition, the 2007 Legislature also passed a measure that explicitly states that the Commission may consider the need for increased renewable energy in rendering decisions on utility matters. Potentially, if energy from a renewable source were more expensive than energy from fossil fuel, the Commission may still approve the purchase of energy from the renewable source. Act 177, signed June 13, 2007; effective July 1, 2007. In enacting Act 177, the Legislature found that: "Progressive energy policy-making at the state level is one of the most important issues on the current legislative agenda."

As noted above, the Commission's IRP Framework required energy utilities to consider demand-side management ("DSM") resources in this planning process, and provided for DSM cost recovery and incentive mechanisms.

SALES FORECAST REDUCTION

Q. Please describe the sales forecast reduction.

A. In the HECO T-2 Rate Case Update filed on November 26, 2008, the Company explained that it revised its sales forecast for 2009 to reflect lowered sales expectations due to high electricity prices and an increasingly pessimistic outlook for the global, national and local economies. The revised forecast was 7,484.7 GWh compared to 7,657.8 GWh in the Company's direct testimony.

Q. Do you know what the recorded GWh sales are so far this year?

A. Through March 2009, the recorded sales were 1,687.3 GWh which would represent an even slower pace than the sales forecast reduction.

Q. How did the Company address the sales forecast reduction for rate case purposes?

A. The Company presented alternatives with and without the sales forecast reduction. The scenario without the sales forecast reduction included the condition that the Company would be able to flow through the impact to the revenue balancing account. The Company explained that decoupling Hawaiian Electric's revenues from sales upon issuance of the interim decision and order in this proceeding would allow Hawaiian Electric to forego incorporating the sales forecast reduction and its revenue and cost impacts into its test year estimates. Rather than recover the shortfall in revenues through the interim increase (or final increase once the Commission issues the final decision and order), the Company would recover any difference between its approved revenue requirement and actual sales through the revenue balancing account. This would defer the impact of the sales forecast reduction to the following year when the RBA balance would be rolled into rates.

The Company stated that if the Commission did not accept the Company's proposal to establish the revenue balancing account at the issuance of the interim decision and order for this rate case, then the impact of the sales forecast reduction should be incorporated into the Company's 2009 test year estimates (Rate Case Update, HECO T-1, pages 4-5, 10-11).

Q. What were the positions of the other parties on the sales forecast reduction?

A. The Consumer Advocate's position was that the best available forecast of test year sales should be used to establish the rate case revenue requirement, so that decoupling adjustments, if decoupling is approved, are zero-based to the extent possible. See CA-T-1, page 43. The Consumer Advocate in its direct testimony proposed to use the sales forecast reduction.. See CA-T-1, pages 44 to 45; CA-101, Schedule 1. The DOD did not use the sales forecast reduction its direct testimony and did not expressly address test year sales and average number of customers.

SETTLEMENT

Q. When did the Consumer Advocate and the DOD file their direct testimonies in this rate case?

A. In accordance with the procedural schedule in this proceeding, the Consumer Advocate and the DOD filed their direct testimonies on revenue requirements on April 17, 2009 and their direct testimonies on rate design on April 28, 2009.

Q. When did the Parties begin settlement discussions for this rate case?

A. Beginning on April 23, 2009 and in the days that followed, Hawaiian Electric had discussions with the Consumer Advocate and the DOD to explore whether the Parties could reach agreement on the various issues in this proceeding. On April 30, 2009, Hawaiian Electric submitted a written settlement proposal to the other Parties. On May 15, 2009, the Parties executed and filed the Stipulated Settlement Letter.

Q. What were the key agreements of the Stipulated Settlement Letter?

A. The following list provides the key agreements of the Stipulated Settlement Letter:

- Include the CIP CT-1 in rate base on an average test year basis (i.e., "base case") and eliminate the CIP CT-1 step increase from the Company's rate case proposal.
- Allow Hawaiian Electric to establish the RBA, to be effective on the date of the interim decision and order in this proceeding.
- Incorporate the impacts of the sales forecast reduction into the 2009 test year estimates.
- Use December 2008 fuel prices rather than the April 2008 fuel prices on which the Companies based their test year estimates in direct testimony.
- Allow Hawaiian Electric to implement the purchased power adjustment clause.
- Increase labor expense reduction to $2.5 million.

Q. Why did the Company agree to eliminate the CIP CT-1 step increase from its proposal?

A. Both the Consumer Advocate and the DOD opposed the inclusion of the full cost of the CIP CT-1 in the test year revenue requirements. However, the joint decoupling proposal that the Company and the Consumer Advocate filed in the decoupling proceeding called for a RAM rate base adjustment in 2010 that would include the actual year-end 2009 plant balances, thereby effecting the inclusion of the full cost of the CIP CT-1 in rate base in 2010.

Q. What did the Parties agree with respect to the RBA?

A. For purposes of settlement, the Parties agreed that the Commission should allow HECO to establish a revenue balancing account as described in its Rate Case Updates to be effective on the date of the interim decision and order. This is consistent with the decoupling proceeding where all parties appear to agree that sales decoupling should be implemented.

Q. What were the implications of incorporating the sales forecast reduction and the December fuel prices into the test year revenue requirement?

A. It resulted in a more realistic revenue requirement for the test year since these revisions made the test year estimates closer to what will actually be experienced in 2009. Hawaiian Electric re-ran its production simulation model and derived test year fuel expense, purchased power expense, ECAC revenue and fuel inventory estimates that were acceptable to all Parties and adopted for revenue requirement purposes.

Q. What was the Consumer Advocate's position on the PPA clause?

A. The Consumer Advocate stated that it was generally satisfied with the purpose of the clause and the manner that the clause will assess and pass through costs to customers. Since the Company indicated that the PPA Clause will be adjusted monthly and reconciled quarterly, the Consumer Advocate recommended that HECO be required to file its calculations with the

Commission at least quarterly and that such calculations be reviewed and approved by the Commission to ensure that customers are appropriately charged for projected purchased power costs. Furthermore, the Consumer Advocate recommended that HECO's filing include all necessary workpapers and supporting documentation that would allow the Commission and other parties to determine that HECO is not recovering purchased power non-energy costs more than once through the different cost recovery mechanisms beyond base rates that will be available to the Company.

Q. How did the Parties settle on the Consumer Advocate's recommendations?

A. For purposes of settlement, the Company agreed to file its calculations (including workpapers and supporting documentation) with the Commission at least quarterly. However, because the PPA Clause would be an automatic cost adjustment clause and will be adjusted monthly, the Company proposed, and the Parties agreed, that explicit Commission approval of each PPA Clause filing will not be practicable nor required. Like other automatic adjustment clauses, the monthly PPA Clause adjustment can be allowed to go into effect at the first of each month, subject to the ability of the Commission to investigate and revise any adjustment and order the refund of any over-collection.

Further, the Company will request explicit approval to recover the non-energy costs associated with a purchased power agreement through the PPA clause, and will not recover such costs through the PPA Clause until the Commission has approved the associated purchased power agreement. The Company will also continue to execute fuel contracts on a long term basis where feasible and execute agreements for non-fossil fuel generation at rates that are de-linked from the price of fossil fuels, in accordance with Section 269-27.2 of the Hawaii Revised Statutes.

Q. Did the Company do anything to mitigate the impacts of the Energy Agreement and other changes on the test year estimates?

A. Yes. The Company initiated a labor expense reduction of $1.7 million. The Company explained that recovery of Energy Agreement-related costs in the 2009 test year was essential to enable Hawaiian Electric to meet its commitments in the time frames required. At the time it filed its rate case application, the Company could not have foreseen what the Energy Agreement would ultimately require and could not have included the requirements in its original test year estimates. The Company acknowledged that the Energy Agreement had comparatively larger impacts than changes experienced in other recent rate case proceedings and specified a number of initiatives requiring regulatory proceedings with short time frames. These requirements will tax the resources of all parties involved in Energy Agreement activities and therefore it is important to facilitate as much as reasonably possible the processing of these proceedings including this rate case. To this end, and to minimize the issues regarding labor expenses in this rate case, the Company proposed the labor expense and associated employee benefit and payroll tax reduction for this rate case only (Rate Case Update, HECO T-1, pages 22-23).

Q. What was the Consumer Advocate's response to the Company's $1.7 million reduction to labor expenses and associated employee benefits and payroll taxes?

A. The Consumer Advocate expressed reservations about the Company's regression methodology and proposed a 2.7 percent vacancy rate representing a midpoint range between the Consumer Advocate's calculation of the 2008 vacancy rate of 3.06 percent and the Company's estimate of 2.37 percent (CA T-3, pages 35 to 38 and 40 to 42). Also, the Consumer Advocate proposed excluding only the Maintenance Division of the Power Supply Department from the employee counts (CA T-1, page 69), rather than the entire Power Supply process area. The Consumer Advocate's proposal translated to a reduction of $2,645,000 in total labor expense, payroll tax, and employee benefits adjustments from the test year and represented an additional $916,000 reduction from HECO's initial labor adjustment (CA-101, Schedule C-13).

Q. What was the DOD's position?

A. In DOD T-1, pages 28 to 31, the DOD proposed a vacancy rate of 3.3 percent, based on a review of the average quarterly 3.35 percent vacancy rate for 2008 (with 10/31/08 used in place of 12/31/08) and the average vacancy rate of all data points from June 30, 2007 through October 31, 2008 of 3.27%. This translated to a labor expense, payroll tax, and employee benefits reduction to the test year of $2,414,000 for the Company, excluding the Power Supply process area (see DOD-120).

Q. What did the Company offer in settlement?

A. To settle the issues in the proceeding, the Company proposed a 2.68 percent vacancy rate, excluding the Operating Division as well as the Maintenance Division of the Power Supply process area, which was accepted by the Consumer Advocate and DOD to reach global settlement. The Company's revised vacancy rate wais derived from an estimated regression function, using additional employee count information for the period from January 2007 through March 2009, submitted in the Company's response to CA-IR-354, filed on January 29, 2009, supplemented on May 5, 2009. The Company's proposal excluded the Operating Division since it must still expend labor expense by incurring overtime to provide round-the-clock coverage or near round-the-clock coverage and operations of the various generating plants (further discussion regarding the duties and responsibilities of the Operating Division is found on HECO T-7, pages 52 to 53), regardless of the vacancy rate it experiences.

The results of HECO's revised vacancy rate estimate translated to a total labor adjustment of $2,521,000, $792,000 more than the Company's initial estimate (see HECO T-15, Attachment 1, Final Settlement). The allocation to the various block of accounts is presented below. The matrix below also summarizes the differences between the Company's most recent estimate and the Consumer Advocate's and DOD's direct testimonies' proposed amounts.

Q. Did the Parties agree on an interim revenue increase for the 2009 test year?

A. Yes. The Parties agreed on an interim revenue increase of $79,820,000 which was specified in the Stipulated Settlement Letter filed on May 15, 2009.

However, as explained earlier, the Company reduced this amount by $9,000 to $79,811,000 due to finalization of the revenue requirement run and reflected the revised amount in its Statement of Probable Entitlement filed on May 18, 2009.

Q. Did the Parties agree on a final revenue increase for the 2009 test year?

A. No. Because the Parties could not reach agreement on the test year non-labor expense amount for informational advertising or the return on common equity to be used for final decision and order purposes, they could not agree on a final revenue increase for the 2009 test year. In the sections that follow, I will briefly summarize the Company's position on these two issues.

CONTESTED ISSUES

Informational Advertising

Q. What is the Company's position regarding information advertising?

A. As stated in HECO T-10 at 52, the Company's test year expense is $1,148,000 as shown in HECO-1003. The estimated expenses include labor costs of $32,000 and non-labor costs of $1,116,000. The Company did not update this estimate in its rate case update.

Q. What is the Consumer Advocate's proposal regarding informational advertising in this rate case?

A. The Consumer Advocate proposed a reduction of $774,000 from the Company's proposed $1,116,000 non-labor informational advertising expense in the test year (CA-101, Schedule C-21).

Q. What is the DOD's proposal regarding informational advertising in this case?

A. In its direct testimony, the DOD did not propose any adjustment to the Company's test year non-labor informational advertising expense and has not taken a position in this issue.

Q. What is the area of focus for your testimony on informational advertising?

A. My testimony will discuss the policy reasons supporting the need for the Company's customer informational advertising efforts and the resources necessary to carry out those plans. Specifically, the Company's request for $1.116 million in non-labor costs for informational advertising (see HECO T-10, page 57 and HECO-1003) is reasonable because the funds will facilitate the advertising effort to support the State's energy policy, make necessary progress toward achieving the utility's required Renewable Portfolio Standards ("RPS") goals as well as State greenhouse gas reduction goals, and help fulfill the Company's obligation to provide energy information to its customers.

Q. Please elaborate on the State's energy policy objectives and the Company's role in helping to achieve them.

A. The State of Hawaii's overall energy policy objectives are summarized in Hawaii Revised Statutes ("H.R.S.") Section 226-18, as follows:

> (a) Planning for the State's facility systems with regard to energy shall be directed toward the achievement of the following objectives, giving due consideration to all:
>
> > (1) Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people;
> >
> > (2) Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased;

(3) Greater energy security in the face of threats to Hawaii's energy supplies and systems; and

(4) Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use.

The 2009 Session of the State Legislature also recently passed HB 1464, which establishes an Energy Efficiency Portfolio Standard of 4,300 GWH by 2030. As a regulated public electric utility, HECO has a fundamental responsibility to play a leadership role in helping achieve all of these objectives.

These responsibilities are more than philosophical. Specifically, the Company is held accountable to meet the RPS promulgated to implement state energy policy (See §269-92 and HB 1464 from the 2009 Legislature, which significantly increases the mandated RPS requirements).

The current RPS includes the impacts of energy savings from energy efficiency measures through the year 2014 (HB1464).

Furthermore, the Company could be subject to penalties if it fails to meet the RPS standards. In its "Decision and Order Relating to RPS Penalties" issued December 19, 2008 in Docket No. 2007-0008, the Commission approved a penalty of $20 for every MWh that an electric utility is deficient under Hawaii's RPS law. In its decision, the Commission found that a penalty, in a specific dollar per MWh amount, which the Commission may assess against a non-compliant utility, will provide clarity and transparency to the RPS Framework. Although the Commission noted that this penalty may be reduced at its discretion, due to events or circumstances that are outside an electric utility's reasonable control to the extent the event or circumstance could not be reasonably foreseen and ameliorated, the possibility of assessment of a penalty is very real.

In addition, the Commission ordered that (1) any penalties assessed against HECO and its subsidiaries for failure to meet the RPS will go into the public benefits fund account used to support energy efficiency and DSM programs and services, which will be operated by a third-party PBF Administrator, unless otherwise directed; and (2) the utilities will be prohibited from recovering any RPS penalty costs through rates.

Q. Are there other relevant requirements that the utility is responsible for meeting?

A. Yes. In July 2007, Act 234 of the 2007 Hawaii State Legislature became law and requires a statewide reduction of greenhouse gas (GHG) emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990. (Act 234, signed June 30, 2007, effective July 1, 2007). The Director of the Hawaii Department of Health is also required to adopt rules before December 31, 2011, which establish emission limits for specific sources or categories of sources of emissions and provide for reporting and verification of statewide emissions and monitoring and compliance. It seems highly likely, given its public utility franchise role, that when these rules are adopted, HECO will be given major responsibility for lowering GHG emissions for the electricity sector. By far the most cost effective means to reduce GHG emissions is to implement energy efficiency.

Furthermore, the Hawaii Clean Energy Initiative to which HECO explicitly committed support by signing the Energy Agreement with the State of Hawaii establishes an overall goal of 70 percent clean energy for electricity and ground transportation by 2030.

Q. When such informational advertising was proposed in prior rate cases, there have been concerns raised about whether such advertising would be effective (Consumer Advocate Opening Brief at 26 to 35, HECO 2005 test year rate case, Docket No. 04-0113)[4]. Since we now have actual experience with an extensive informational advertising campaign, what have we learned about its effectiveness in supporting the aforementioned requirements?

A. As discussed in HECO-RT-10A, the Company's integrated advertising campaign utilizing a very identifiable and credible spokesperson (Jade Moon) has been successful in promoting energy efficiency. In fact, we now have the results from a survey that demonstrate how effective HECO's advertising efforts have been.

The evaluation report for the Residential Customer Energy Awareness Program found that, as a result of the advertising efforts undertaken by the Company in 2007 and 2008, almost 94% of Oahu residents surveyed recalled at least one of six messages or advertising elements from Hawaiian Electric and nearly half of all respondents (47%) reported they did something

[4] The Department of Defense's ("DOD") position on this issue in the 2005 HECO test year rate case, Docket No. 04-0113, was (1) to remove the $750,000 additional funding requested due to the increase being introduced for the first time in HECO's rebuttal testimony which DOD felt it did not have sufficient time to investigate and comment, and (2) the issue should be addressed in the

differently in order to conserve after seeing or hearing an energy conservation ad.

Q. Given the quantifiable results of the Company's advertising efforts and the fact that the Company is held responsible for meeting several standards promulgated to help achieve state energy policy, is it reasonable for the Company to be granted the resources to help achieve those goals?

A. Yes. As discussed above, the Company is responsible for meeting the RPS requirements, which includes an energy efficiency component through 2014, and the state's greenhouse gas reduction goals. The Company is also subject to potential penalties for not meeting these requirements. Thus, the Company should be provided the tools (advertising funds) to help achieve those standards and goals. Public awareness is a key element to the behavioral change necessary to engender energy saving actions and mass market advertising is needed to build and sustain such awareness.

Q. Is the importance of utility customer advertising especially valuable at this point in time?

A. Yes. The importance of utility advertising is even more critical during this period of time as the energy efficiency programs are transitioned to the Public Benefits Fund ("PBF') Administrator. The PBF Administrator is faced with meeting ambitious and necessary energy efficiency goals, with tight program budgets and during a challenging economic environment in which it is even

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Energy Efficiency Docket, Docket No. 05-0069 (DOD Opening Brief at 9, 2005 test year rate case, Docket No. 04-0113).

more difficult for residents and businesses to afford energy efficiency upgrades. Furthermore, fuel prices have retreated significantly from the record highs of last year, lowering electricity prices and removing some of the incentive to pursue energy efficiency.

Meeting the State's challenging RPS and GHG reduction targets, as well as the specific energy efficiency achievements committed to by the PBF Administrator, mean that not only must the energy awareness already established must be maintained, it must also be increased.

As will be discussed in more detail in Ms. Unemori's rebuttal testimony HECO RT-10A, the PBF Administrator's budget provides for a small commitment of resources for advertising, making it unlikely it will be able to increase, let alone maintain, the current level of energy awareness established by the Company's efforts.

Q. What is expected to happen to this momentum if there is a significant drop off in energy conservation and efficiency advertising?

A. As discussed in HECO RT-10A, it is a well established marketing principle that a significant lull in advertising will not only quickly result in a loss of awareness achieved by earlier marketing efforts, it will also require the expenditure of even greater amounts in order to regain that same level of awareness later. Achieving consumer attitudinal change needed for sustained behavior change requires sustained communication.

Q. Given the transfer of the Energy Efficiency programs to the PBF Administrator, are there other reasons why the Company should continue to conduct customer informational advertising related to energy efficiency and conservation?

A. Yes. The Company's responsibility for aggressively communicating with its customers about energy efficiency and conservation does not end with the transfer of the administration of the DSM energy efficiency programs to the PBF administrator. The Company also has a fundamental obligation to provide energy efficiency information to its customers. Similarly, customers have an expectation that their utility will be a major source of this advice. It is incongruous to think that a utility would not be expected to provide such information to its customers.

Furthermore, if customers receive energy conservation and efficiency information from multiple sources, it reinforces those messages, increases penetration and increases the chances customers will take action. The responsibility for promoting energy efficiency is a shared one. It is very important to have an ongoing integrated campaign of advertising to help bring about long-term behavioral change.

In addition, as will be addressed in more detail in Ms. Unemori's RT-10A, HECO's energy efficiency and conservation advertising will focus on measures not necessarily related to the specific measures promoted by the PBF Administrator's customer rebate programs. HECO will also focus more on educating the public about the importance of reducing energy use during peak times. This is not expected to be a primary focus of the PBF Administrator's advertising efforts.

Q. In addition to providing information to its customers regarding energy efficiency and conservation, does the Company have a responsibility to provide any other information to its customers via advertising?

A. Yes. The Company also has an obligation to educate customers through advertising on other important topics such as general electrical safety, equipment protection, Rule 16 information on rights for submitting damage claims, and outage prevention education such as the Company's metallic balloon awareness campaign and its Arbor Day "right tree, right place" program. Customer advertising also supports important initiatives such as the Sun Power for Schools program.

Q. If the Commission agrees with the Company, when will be the next opportunity to re-evaluate this issue?

A. Assuming a favorable decision in the decoupling docket, Docket No. 2008-0274, there will be an opportunity to further evaluate this issue in HECO's planned 2011 test year rate case. This would allow time for the PBF Administrator to fully transition into its new role and provide a track record for an updated evaluation of the appropriate interplay of advertising by the Company and the PBF Administrator.

Q. Please summarize your testimony regarding informational advertising.

A. HECO's request for $1.116 million in non-labor costs for informational advertising is reasonable and justified because the funds will facilitate the advertising effort to support the State's energy policy, make necessary progress toward achieving the utility's required RPS and GHG reduction goals, and help fulfill the Company's obligation to provide energy information to its customers. Furthermore, the successful advertising conducted by the Company over the past several years has created a level of momentum in energy efficient behavior that must be maintained even during a period of transition to the PBF Administrator. If the utility is not granted these resources, there is a risk that the level of awareness and related energy efficiency actions taken will rapidly decline at a time when even greater energy efficiency progress is needed.

Return on Common Equity

Q. What return on common equity ("ROE") have the Consumer Advocate and the DOD proposed for the 2009 test year?

A. The ROE recommended by each witness is as follows:

Mr. Hill	9.5%
Mr. Parcell	9.5% -10.5%

Q. Has the Company changed its proposed ROE estimate from what was proposed in direct testimony?

A. Yes. In direct testimony, the Company's return on common equity witness, Dr. Roger Morin, recommended an ROE of 11.25%. Dr. Morin's recommendation was based on an average 11.0% based on the results of four risk premium studies and two discounted cash flow ("DCF") studies on two surrogates. To this estimate, Dr. Morin raised the estimate upward to 11.25% to account for Hawaiian Electric's slightly higher risk due to its relatively small size and the presence of debt-equivalent obligations. In his rebuttal testimony, Dr. Morin concludes that based on the results of all of his analyses, the application of his professional judgment, the risk circumstances of Hawaiian Electric, and the unsettled current market environment, a conservative just and reasonable return on the common equity capital of Hawaiian Electric's electric utility business is in a range of 11.00% - 11.25% assuming approval of decoupling in its existing format and in a range of 11.25% - 11.50% without.

Q. Given the fact that it has been approximately eight months since Dr. Morin filed his direct testimony, has he taken into account the sweeping changes that have taken place since that time?

A. Yes, he has. In Dr. Morin's rebuttal testimony, HECO RT-19, he describes in detail the volatility of the capital markets and the stock market, and the unprecedented corporate interest rate spreads in the debt market. He also describes how there is now increased risk aversion and market illiquidity that have resulted in higher borrowing costs for corporations.

Q. Did Dr. Morin take into account the various Energy Agreement recovery mechanisms that are before the Commission for approval?

A. Yes, he did. However, Dr. Morin also pointed out that there are other significant factors to consider: 1) the weakening Hawaiian economy; 2) the Company's dependence on external funding to finance its capital program; 3) uncertain feasibility and unknown costs of the CEI plans; and 4) regulatory risks since the details of major provisions of the CEI are not known. Dr. Morin feels that these different factors largely offset the Energy Agreement revenue recovery mechanisms that are currently under review by the Commission.

Q. With all of these changes, did Dr. Morin redo his analyses to determine if his recommendation would change with the different economic and market conditions that exist now?

A. Yes. Dr. Morin redid all the analyses he did earlier except for one and updated/modified some of the study factors to better reflect current economic conditions. Based on his most recent analyses, the average result from all of the methodologies is 11.3%, rounded to 11.25% to the nearest quartile. Dr. Morin also concluded that the risk adjustment of 25 basis points that he estimated as a risk premium in direct testimony was no longer necessary. Based on the results of all his analyses, the application of his professional judgment, the risk circumstances of Hawaiian Electric, and the unsettled current market environment, it is his opinion that a conservative just and reasonable return on the common equity capital of Hawaiian Electric's electric utility business is in a range of 11.00% - 11.25% assuming approval of decoupling in its existing format and in a range of 11.25% - 11.50% without.

Q. Given Dr. Morin's recommended range of 11.0% - 11.25% assuming approval of decoupling, what ROE is Hawaiian Electric proposing to be used for the 2009 test year?

A. As stated in the rebuttal testimony of Ms. Tayne S. Y. Sekimura, the Company is willing to accept a rate of return on common equity at the low end of the range provided by Dr. Morin, 11.00%, with the proposed decoupling mechanism.

Q. Does this conclude your testimony?

A. Yes, it does.

HECO RT-10A
DOCKET NO. 2008-0083

TESTIMONY OF
LYNNE T. UNEMORI

VICE PRESIDENT
CORPORATE RELATIONS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Service Expense (Informational Advertising Expense)

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lynne Unemori and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Vice President, Corporate Relations at Hawaiian Electric Company, Inc. ("HECO" or "Company"). HECO-10A00 provides my educational background and work experience.

Q. What is the area of focus for your testimony?

A. My testimony will discuss additional justification for the Company's request for $1.116 million in non-labor costs for informational advertising and why the Consumer Advocate's proposal to decrease the informational advertising spending by $774,000 will leave the Company with insufficient advertising resources to fulfill the Company's responsibilities. My testimony will supplement the compelling policy reasons discussed in Mr. Alm's testimony RT-1, which explained that the funds will facilitate the advertising effort necessary to support the State's energy policy, make necessary progress toward achieving the utility's required RPS and GHG reduction goals, and help fulfill the Company's obligation to provide energy information to its customers. Mr. Alm further made the point that because the Company is held accountable for meeting several standards and goals designed to support State energy policy, it is reasonable to provide the Company with the resources to help meet these requirements.

Specifically I will discuss how the funding levels and messages that comprise HECO's informational advertising are not necessarily the same as those for the PBF Administrator. Since the advertising efforts of HECO and the PBF

Administrator are not completely interchangeable, any increase in PBF Advertising does not necessarily eliminate the need for HECO informational advertising. Therefore, HECO should be provided a level of advertising funding independent of the PBF Administrator.

Q. What is the Company's position on informational advertising expense in direct testimony and rate case update?

A. As stated in HECO T-10 at 52, the Company's test year informational advertising expense is $1,148,000 as shown in HECO-1003. The estimated expenses include labor costs of $32,000 and non-labor costs of $1,116,000. The Company did not update this estimate in its rate case update.

Q. What is the Consumer Advocate's position on informational advertising expense in its direct testimony?

A. The Consumer Advocate proposed a negative adjustment of $774,000 to informational advertising non-labor expenses. This adjustment amount was derived by averaging utility advertising expenses from 2006 to 2008, and subtracting the average recorded expense amount from the $1,116,000 non-labor expenses (CA-T-1 at 114 to 118; CA 101, Schedule C-21).

Q. What is the Department of Defense's ("DOD") position on informational advertising expense in its direct testimony?

A. DOD has not taken a position regarding informational advertising.

Q. What are the funding level differences between the advertising budget for the PBF Administrator and HECO's historical energy efficiency expenditures?

A. The PBF Administrator's advertising efforts are not likely to be anywhere near as extensive as what the Company has conducted in the recent past to increase energy awareness amongst its customers and effect extraordinary decreases in energy use. The Company invested $3,500,390 and $2,924,519 in energy efficiency and other informational advertising in 2007 and 2008, respectively. This includes amounts charged to utility operating expenses, the RCEA program, and residential and commercial DSM advertising (almost all of this was for advertising directed at residential customers). (CA-IR-416 at 2.)

By contrast, the budget included in the PBF Administrator's contract with the Commission averages out to a total of just $404,000 a year for both residential and commercial advertising. Based on discussion with the PBF Administrator, it appears that funding would be used to (1) establish a new brand, (2) market the energy efficiency programs, and (3) provide any ongoing energy awareness messaging to support long-term consumer attitudinal and behavioral change.[1]

Q. When such informational advertising was proposed in prior rate cases, there have been concerns raised about whether such advertising would be effective (Consumer Advocate Opening Brief at 26 to 35, HECO 2005 test year rate case, Docket No. 04-0113)[2]. Since we now have actual experience with an extensive informational advertising campaign, what have we learned about its effectiveness in supporting the aforementioned requirements?

A. As discussed by Mr. Alm in RT-1, the Company's energy efficiency and conservation advertising has been successful. As a result of the advertising efforts undertaken by the Company in 2007 and 2008, almost 94% of Oahu residents surveyed recalled at least one of six messages or advertising elements from

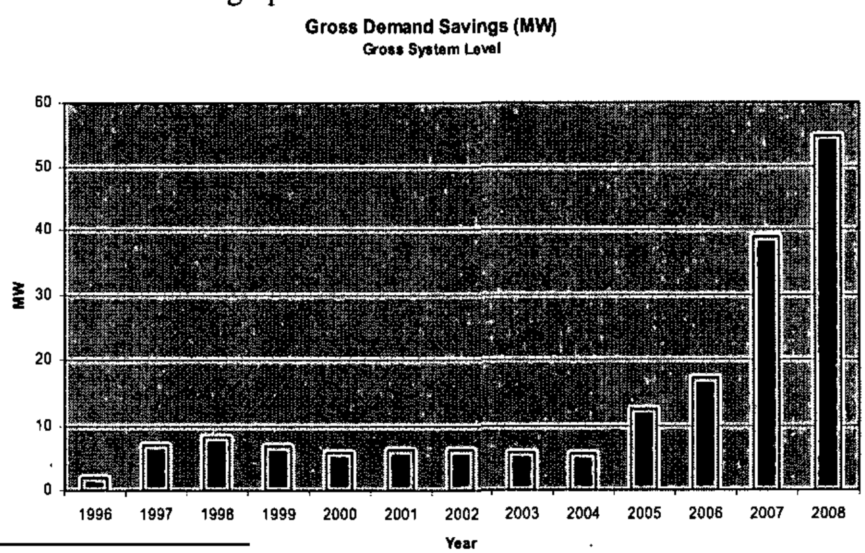
[1] Attachment F of the "Hawaii-SAIC Contract for Program Administration" allows for a total of $423,490 and $517,598 for residential and C&I program advertising, respectively, for the 28-month period from March 3, 2009 to June 30, 2011.

[2] The DOD position on this issue in the 2005 HECO test year rate case, Docket No. 04-0113, was (1) to remove the $750,000 additional funding requested due to the increase being introduced for the first time in HECO's rebuttal testimony which DOD felt it did not have sufficient time to investigate and comment, and (2) the issue should be addressed in the Energy Efficiency Docket, Docket No. 05-0069 (DOD Opening Brief at 9, 2005 test year rate case, Docket No. 04-0113).

HECO and nearly half of all respondents (47%) reported they did something differently in order to conserve after seeing or hearing an energy conservation ad. The campaign also benefited from the Company's use of a very identifiable and credible spokesperson (Jade Moon).

In fact, 87% of respondents reported awareness of compact fluorescent lights (CFLs) and 70% were aware of the ENERGY STAR® label as an indicator that an appliance was energy-efficient (see CA-IR-401, Attachment 1 at 5, 11 to 13, and 16 to 23 (Ward Research Report "Residential Customer Energy Awareness Program Evaluation," September 2008, resubmitted as Rebuttal Exhibit HECO-R-10A01).

In addition, as a result of the 2007 and 2008 advertising campaigns, as well as other factors during that time (e.g., customer reaction to the impact of rising fuel prices), incremental demand savings increased significantly in those two years as shown in the graph below.[3]



[3] The graph of demand savings is at the gross generation level and includes free-riders and contract curtailable load from load management programs. The amount of curtailable load included from the load management programs is 6.1MW, 9.1MW, 18.9MW and 14.2 MW, in 2005, 2006, 2007, and 2008, respectively. The original of this graph was filed as Figure 1 on page 1 of HECO's Accomplishments and Surcharge ("A&S") Report, March 31, 2009, Docket No. 2007-0341. This graph has been updated by applying the results of the 2005-2007 DSM impact evaluation results to 2005-2008.

Q. What is the impact of the PBF Administrator's lower advertising budgets on the effectiveness in delivering energy awareness messages?

A. It does not appear the PBF Administrator's advertising budget will be sufficient to provide the level of energy awareness that HECO was able to deliver in 2007 and 2008. In fact, the PBF Administrator has already approached the Company to discuss, on a preliminary basis, the possibility of supplementing the PBF Administrator's advertising efforts with Company advertising in order to achieve two of its three objectives (1) help establish a new overall brand for the energy efficiency programs and (2) to promote customer energy awareness needed for long-term attitudinal and behavioral change.

The Company agrees with the PBF Administrator that establishing a new overall brand for the energy efficiency programs is an important initial step in the transition to third-party administered programs. However, it will be difficult to successfully execute a major rebranding effort even if the PBF Administrator were to devote the total amount in its advertising budget to this objective. Major rebranding campaigns to reach a mass audience normally require extensive planning and the investment of millions of dollars to carry out the marketing needed to ensure the establishment of the new brand.

As a practical matter, however, the PBF Administrator will probably need to allocate some of those funds to actually market the specific energy efficiency programs. Thus, it is likely that a large portion of the advertising conducted by the PBF Administrator will be focused on providing information about the specific programs, i.e., "sales-oriented" marketing, in order to achieve its energy efficiency targets. This will leave the remaining, smaller, portion of the budget for overall energy awareness messaging.

Q. Why should the Commission accept HECO's test year expense estimate for informational advertising rather than increase the budget of the PBF Administrator?

A. The messages that comprise HECO's informational advertising are not necessarily the same as those for the PBF Administrator. Thus, increasing the PBF Administrator's advertising budget instead of approving HECO's informational advertising expense estimate will not provide the breadth of energy awareness messaging that HECO can deliver and that customers should receive.

Q. How do the advertising messages differ between HECO and the PBF Administrator?

A. HECO's informational advertising will focus on (1) energy efficiency and conservation measures not necessarily related to energy efficiency measures promoted by the PBF Administrator's customer rebate programs and (2) on educating the public about the importance of reducing energy use during peak times. It is expected that the PBF Administrator's goals and advertising likely will be focused, as it should be, on meeting the energy reductions committed to in its contract and not necessarily on how customers should use energy wisely at peak times or during an emergency.

Q. Please describe HECO's advertising messages in more detail.

A. HECO's advertising will focus on overall general energy efficiency and conservation information to help build attitudinal change which results in such behavior becoming a way of life for customers. Such messaging will provide general energy efficiency and conservation tips designed to not only promote awareness of the long-term benefits to our state of reduced energy use, but also focus on many changes in energy use habits that customers can take and still maintain a modern, convenient lifestyle. Some of HECO's advertising will complement the PBF Administrator's efforts by recommending actions (e.g., install solar water heaters, buy Energy Star appliances, install CFLs) that direct customers to the PBF Administrator's programs. However, other advertising conducted by HECO will identify actions that are not related to the PBF Administrator's programs, e.g., turning off light, watching out for phantom loads, taking shorter showers, etc.

In addition, the Company has a need to continue to educate the public about the importance of reducing energy use during peak times. This is not only important from an overall system planning standpoint to help defer the need for new generation to meet peak demand, but also especially critical when generating reserve margins are tight when generating units are taken out of service for planned and unplanned maintenance.

Previous focus group research commissioned by the Company and conducted by research professionals has found that many of the focus group participants "do not understand the "peak" load concept, which leads to some misunderstanding of the EAM (emergency alert messages)." (See HECO Opening Brief at 67, HECO Reply Brief at 31, HECO 2005 test year rate case, Docket No. 04-0113.) Therefore, there is a need for HECO to explain to customers why these concepts are important to them. These messages are not at all related to the efforts of the PBF Administrator and the PBF Administrator should not be expected to use its advertising resources to communicate these concepts to the community.

With the planned incorporation of more intermittent renewable energy resources onto HECO's grid to meet state policy goals, managing peak time demand and educating the public about peak load concept and the impact of renewable energy resources will be even more critical.

Q. Has the Commission previously commented on the importance of the Company's efforts to educate its customers about energy matters, including conservation?

A. Yes. In the Residential Customer Energy Awareness ("RCEA") Docket No. 03-0142, the Commission stated that "The [C]ommission understands HECO's desire and need to educate its residential customers about energy matters, including conservation. We further recognize that educating residential customers to encourage energy conservation and make them aware of (1) measures that can be taken during the crucial 5:00 to 9:00 p.m. priority peak; and (2) their impact on the need for future electrical generation may provide some relief to HECO in reducing peak loads, which ultimately will assist HECO in maintaining its generation system reliability guideline." (Docket No. 03-0142, Decision and Order No. 21756, issued April 20, 2005, at 9 to 10.)

Q. In addition to this information, is there other customer information the Company has a responsibility to provide its customers?

A. Yes. As discussed by Mr. Alm in RT-1, the Company also has an obligation to sufficiently advertise other important customer information such as general electrical safety, equipment protection, Rule 16 information on rights for submitting damage claims, outage prevention education such as the Company's metallic balloon awareness campaign and its Arbor Day "right tree, right place" program. Customer advertising also supports important initiatives such as the Sun Power for Schools program.

Q. Has the Consumer Advocate previously taken the position that suggests the Company is expected to provide ongoing information to help customers better manage electricity consumption?

A. Yes. In Docket No. 2008-0074 regarding the Company's proposed Dynamic Pricing Program, the Consumer Advocate's Statement of Position ("SOP") states at page 28 "the Company should take advantage of ongoing customer education efforts to help customers better understand the potential impact of this program on their own bills as well as how it affects the system." The SOP further states on the same page "HECO can make use of already developed media to help consumers to better understand the goals of the program as well as how to better manage their electricity consumption and gain greater control over their electric bills."

Q. How does the Company plan to use the test year budget for non-labor informational advertising dollars?

A. Following is a detailed breakdown of the planned use of the test year advertising budget to effectively communicate the information discussed above.

Production:	
Television (Two 30-second spots)	$ 175,000
Radio (Four 60-second spots)	11,000
Print (ads, inserts)	35,600
Music	25,000
Website	9,000
Media:	
Television	462,000
Radio	211,000
Print	187,400
Total	$1,116,000

Q. How much has the Company spent year to date in the test year on informational advertising?

A. As of May 20, 2009, the Company had already effectively incurred $470,000 in utility O&M informational advertising costs, including $283,000 for advertising invoices received and/or processed and approximately $187,000 in additional pending billings for advertising work already completed or committed to. This advertising includes the sponsorship of a very successful Green Hawaii magazine tabloid included in Hawaii Home and Remodeling, Hawaii Business and Honolulu magazines in April 2009 for Earth Day, as well as ongoing television, radio and print advertising to promote energy efficiency measures, the Rule 16 damage claim insert, the metallic balloon safety campaign and the Sun Power for Schools program. HECO provided quarterly commitments for print, radio, and television advertisement in Attachment 4 to the response to CA-IR-416.

It should also be noted that because DSM advertising is continuing through June 30, 2009, at which time the energy efficiency programs will be transferred to the PBF Administrator, the Company's advertising plan for 2009 assumed a greater proportion of the advertising paid for through O&M funds would take place in the second half of the year.

Q. If the test year amount for informational advertising of $1,116,000 is reduced by $774,000 as proposed by the Consumer Advocate, will the remaining funding be sufficient to fulfill the Company's responsibilities and accomplish the objectives discussed in this rebuttal testimony and in Mr. Alm's RT-1?

A. No. Achieving attitudinal and behavioral change takes a sustained mass media effort to continually reinforce information with the public. The remaining $342,000 for informational advertising will not support any mass market campaign, especially in an environment with climbing advertising rates, a reduced supply of commercial time availability and proliferation of mass market vehicles. (CA-IR-125 at 4; CA-IR 402 at 2).

A key component of mass media advertising is television advertising. In the last two years, due in large part to the shrinking supply of commercial time availability, the cost for television advertising has increased significantly. As an example, two years ago, $100,000 bought airtime for two four-week television schedules reaching at least 98% of all Adults 25-64 at least 4.5 times. Today, that cost has doubled. And that does not even include the cost to produce the spot, which can vary widely depending on how simple or complex the concept (i.e., "production value") for the spot is. Radio airtime, like television, has incurred double-digit increases (CA-IR-125 at 4).

The $1,116,000 budgeted amounts to only roughly one-third of the total amount spent on customer informational advertising (including utility O&M, DSM, and RCEA) in each of the past two years. However, while the level of funding requested in the rate case would not allow a campaign as aggressive as was proposed, it will still provide a greater opportunity for the messages to take root than the amount proposed by the Consumer Advocate.

Q. What is expected to happen to this momentum if there is a significant drop off in energy conservation and efficiency advertising?

A. It is a well established marketing principle that a significant lull in advertising will not only quickly result in a loss of awareness achieved by earlier marketing efforts, it will also require the expenditure of even greater amounts in order to regain that same level of awareness later. Achieving consumer attitudinal change needed for sustained behavior change requires sustained communication.

> "Individual studies conducted following eight separate recessions from 1923 to 1982 were unanimous in their findings: Companies that reduce marketing communications budgets in a downturn lose sales and market share and take longer to recover." *(Wireless Design & Development, "Maintain Your Marketing during Hard Times"; Chris Burke, President, BtB Marketing Communications)*

> "Persistence remains a critical issue…energy conservation is a job that is never done and requires vigilance and constant reminders." "Making behavior changes become a habit will take a long time and a large commitment of funds." *("Using Mass Media to Influence Energy Consumption Behavior: California's 2001 Flex Your Power Campaign as a Case Study," Sylvia Bender, California Energy Commission; Mithra Moezzi, Lawrence Berkeley National Laboratory; Marcia Hill Gossard, Washington State University; Loren Lutzenhiser, Washington State University)*

Q. What is the policy recommendation related to energy efficiency education of the 2006 National Action Plan ("NAP") for Energy Efficiency[4], facilitated by the Environmental Protection Agency ("EPA")?

A. One of five key policy recommendations of the National Action Plan is to "Broadly communicate the benefits of and opportunities for energy efficiency." The NAP identifies investing in education, training, and outreach as a "best practice" in the design and delivery of energy efficiency programs. NAP at 6-10. This recommendation is made by the NAP despite the recognition that "Capturing the energy impacts of energy education programs has proven to be a challenge for evaluators for various reasons. [E]ducation and training efforts are not always designed to achieve direct benefits. They are often designed to inform participants or market actors of program opportunities, simply to familiarize them with energy efficiency options." NAP at 6-49 to 6-50.

Q. Has the NAP been supplemented by additional studies meant to move from the plan to implementation?

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[4] http://www1.eere.energy.gov/office_eere/napee.html

A. Yes. In November 2008, the National Action Plan for Energy Efficiency Vision for 2025 ("Vision")[5] was issued jointly by Ms. Marsha H. Smith, President of the National Association of Regulatory Utility Commissioners, and Mr. James E. Rogers, President, Chairman, and CEO, Duke Energy, and facilitated by the EPA. The Vision confirmed the NAP key policy recommendation above regarding the communication of energy efficiency benefits. The Vision also added 10 goals, including Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms, that incorporates the creation of strong public education programs for energy efficiency. In further describing education as an implementation step, the Vision stated, "Public education is an important element of encouraging customers to take advantage of available energy efficiency programs as well as to take greater control of their energy costs through energy saving measures they can undertake themselves. Many states and utilities have public outreach efforts, but greater integration with energy efficiency programs, both at the state and regional level, and leveraging the national ENERGY STAR® platform can increase overall effectiveness." The Vision, therefore, reinforced the need for public education efforts, which HECO can and should provide through its informational advertising activities.

Q. Please address the Consumer Advocate's argument that "Company spending on advertising, outside of DSM and RCEA, has been less than $1 million" a year (CA-T-1 at 116 to 117).

A. It is inappropriate to view Company's advertising historical expenditures by excluding DSM and RCEA advertising spending. The Company has conducted an

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[5] Ibid.

integrated campaign that leveraged the totality of these funds to maximize the media buying power of every incremental dollar spent on advertising. Advertising airtime, like many commodities, offers volume discounts. Every additional dollar spent on buying media air and print time results in more value for that dollar by achieving incrementally greater reach and frequency.

Furthermore, if not for the Commission's approval of the RCEA program, the Company would have spent more in "utility" O&M advertising. However, with RCEA and DSM funds, advertising expenditures totaled close to $3 million a year for the last two years. That level of advertising in 2008 was designed to reach 99% of the target market with 150 exposures to energy efficiency advertising a year.

Q. The Commission's D&O No. 24171 in the HECO's 2005 Rate Case stated that the Company's request for an additional $750,000 advertising to bring total utility O&M informational advertising to $1 million was "moot" because it had approved the RCEA pilot program. Please comment on this.

A. The Company maintains that the issue is no longer moot because the RCEA pilot program has ended. The Company recognized that some level of advertising would be performed by the PBF Administrator, and thus did not budget for O&M informational advertising at as a high a level as the RCEA program. But since the RCEA program was discontinued, it is reasonable to restore utility advertising to levels that will at least partially allow for a base level of mass media marketing to maintain the awareness and momentum established by the advertising efforts over the last several years. This is especially reasonable after adjusting for inflation and considering the additional Energy Agreement requirements of "Telling the Energy Story." (CA-IR-402 at 2 to 3.)

Q. In its testimony the Consumer Advocate suggests that if the Commission believed it reasonable to expand conservation advertising but wanted to track and regulate such spending, it could provide additional funding to HECO or the PBF Administrator through the DSM/PBF surcharge (CA-T-1, page 116, lines 4 – 10). What is HECO's position?

A. HECO maintains that because the Company has a fundamental obligation to provide energy conservation information to its customers, informational advertising is a base activity and should, therefore, be recovered through base rates. In addition, if the Commission wanted to track and review the Company's activities in information advertising between rate cases, HECO is willing to report on those activities and actual expenses on an annual basis following the completion of the calendar year.

Q. Please summarize the Company's position regarding informational advertising expense.

A. HECO's request for $1.116 million in non-labor costs for informational advertising is reasonable because the funds will facilitate the advertising effort necessary to support the State's energy policy, make necessary progress toward achieving the utility's required RPS and GHG reduction goals, and help fulfill the Company's obligation to provide energy information to its customers. In addition, the funding levels, and messages that comprise HECO's informational advertising are not necessarily the same as those for the PBF Administrator. Since the advertising efforts of HECO and the PBF Administrator are not completely interchangeable, any increase in PBF Advertising does not necessarily eliminate the need for HECO informational advertising. Therefore, HECO should be provided a level of advertising funding independent of the PBF Administrator.

Moreover, HECO is currently in a transition period with the PBF Administrator. Under decoupling, HECO is expected to file another rate case in 2011. If at that time, the PBF Administrator has the energy efficiency programs up and running and if it determines that it should implement an RCEA-like program, then the interplay of Company and PBF Administrator advertising can be revisited. But during this critical transition period, in order to insure no momentum is lost, continuation of uninterrupted advertising is a key success factor to the State's energy efficiency efforts.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

Lynne T. Unemori

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813
Position:	Vice President, Corporate Relations
Education:	B.S. Accounting, University of Hawaii at Manoa
Previous Positions:	Director, Corporate Communications Senior Communications Consultant/Editor, Corporate Communications Communications Specialist, Corporate Communications Director, Taxes and Depreciation Other professional positions with Coopers & Lybrand CPAs
Professional Certifications:	Certified Public Accountant (not in public practice) State of Hawaii
Other Testimony:	None

WARD RESEARCH
INCORPORATED

RESIDENTIAL CUSTOMER ENERGY AWARENESS (RCEA)

PROGRAM EVALUATION

Prepared for:

HAWAIIAN ELECTRIC COMPANY

September 2008

Ward Research, Inc. • 828 Fort Street Mall, Suite 210 • Honolulu, Hawaii 96813 • Phone: (808) 522-5123 • Fax: (808) 522-5127

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EXECUTIVE SUMMARY

These findings summarize the evaluation of Hawaiian Electric's Residential Customer Energy Awareness (RCEA) Program. The objectives for this evaluation were to determine if an aggressive customer communications program can 1) change levels of residential customer awareness of energy options; and 2) encourage customers to adopt energy efficient appliances and behavior.

Hawaiian Electric Company implemented a multi-faceted communications campaign in June 2007, as part of the RCEA Program. Ward Research, Inc., conducted three telephone surveys related to the RCEA campaign. The surveys measured levels of advertising awareness and recall of conservation messages; perceptions/understanding of sources of energy consumption in the household; awareness of peak period; and awareness of residential energy conservation measures and reported behaviors related to those measures. The baseline survey was conducted May 1-12, 2007, among n=403 Oahu residents, and the final (Wave III) survey was conducted June 12-23, 2008, among n=401 Oahu residents.

More than nine in ten respondents (93.8%) recalled at least one of six messages/advertising elements from Hawaiian Electric and nearly half of all respondents (46.6%) reportedly did something differently in order to conserve energy after seeing or hearing an energy conservation ad. Based on survey results, the RCEA Program has been successful in both generating awareness of energy options and in prompting residents to take steps to conserve energy.

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Measure	%
Recall of six messages/advertising elements from Hawaiian Electric	93.8%
Took action as a result of advertising	46.6%
Installed or switched to CFLs	27.2%
Turned off lights	13.2%
Overall awareness: CFLs	87.3%
Overall awareness: ENERGY STAR®	69.8%
Base =	(401)

Nearly three-fifths of the respondents who said that they did something differently as a result of seeing or hearing energy advertising (58.3% or 27.2% of the total sample) said that they installed or switched to CFLs and nearly three out of ten (28.3% or 13.2% of the total sample) said that they turned off lights or used fewer lights.

More than three in four respondents overall (76.6%) recalled ads featuring CFLs. Reported awareness of CFLs or compact fluorescent bulbs is very high at 87.3%. Four in five respondents (81.3%) indicated awareness of CFLs unaided (without a description) and another 6.0% said that they had heard of CFLs after being read a description of CFLs. One-half of all respondents (50.6%) reportedly installed CFLs in their homes in the past year and one-fifth (20.9%) suggested installing CFLs when asked for things that residents could do to lower their energy bill.

Nearly two-thirds of respondents (63.3%) said they saw an ad relating to ENERGY STAR®. Overall, seven in ten respondents indicated awareness of ENERGY STAR (69.8%). Seven in ten respondents (71.3%) also mentioned the ENERGY STAR label as an indicator that one appliance is more efficient than another.

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Key messages from the RCEA campaign, then, were played back strongly in the post-campaign surveys conducted. Similarly, self-reported data underscored the adoption of energy efficient appliances and conservation behaviors. These two findings support the successful achievement of Hawaiian Electric's stated goals ("to determine if an aggressive customer communications program can 1) change levels of residential customer awareness of energy options; and 2) encourage customers to adopt energy efficient appliances and behavior".)

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OBJECTIVES AND METHODOLOGY

The objectives for this evaluation of the RCEA Program were to determine if an aggressive customer communications program can change levels of residential customer awareness of energy options and encourage customers to adopt energy efficient appliances and behavior.

A telephone survey of n=403 Oahu residents was conducted May 1-12, 2007, prior to the launch of Hawaiian Electric's RCEA campaign. A second wave of the survey was conducted on November 1-10, 2007, among n=400 residents. The final survey was conducted June 12-23, 2008, among n=401 residents.

	Data Collection Period	Sample Size	Maximum Sampling Error at 95% Confidence Level
Wave I	May 1-12, 2007	n=403	+/-4.9%
Wave II	November 1-10, 2007	n=400	+/-4.9%
Wave III	June 12-23, 2008	n=401	+/-4.9%

The objective of the surveys was to help Hawaiian Electric track awareness of energy issues and messages among Oahu residents. Specifically, the surveys sought to find reported levels of advertising awareness and recall of conservation messages; perceptions/understanding of sources of energy consumption in the household; awareness of peak period; awareness of residential energy conservation measures and reported behaviors related to those measures; and beliefs on key attitudinal statements related to energy conservation. (See attachment for full survey results.)

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The survey instruments were based on the draft survey instrument included in Hawaiian Electric's application to the Public Utilities Commission in Docket no. 03-0142 and modified only slightly by Hawaiian Electric and Ward Research. Hawaiian Electric was not identified as the sponsor of the research. The final survey instrument was nearly identical to the instrument used in the baseline; copies of these are in the Appendix.

A random digit dialing (RDD) method was used to generate phone numbers for this study in order to reach households with listed and unlisted phone numbers. All interviewing was conducted from the Calling Center in the Ward Research downtown Honolulu office. The Calling Center is equipped with a Computer Assisted Telephone Interviewing (CATI) system, which allows for the 100% monitoring of calls through a combination of electronic and observational means. Prior to interviewing, the questionnaire was pre-tested for length and to ensure questionnaire language flows smoothly and is easily understood. Data processing was accomplished using SPSS for Windows, an in-house statistical software package.

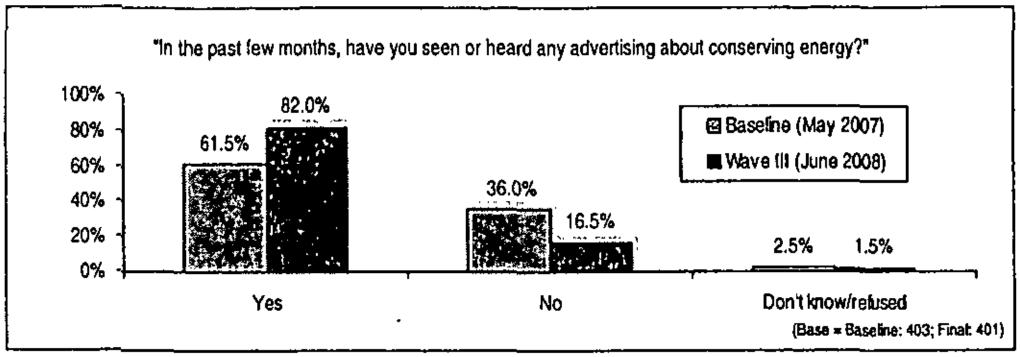
A copy of the detailed findings can be found in the report "Residential Customer Energy Awareness Campaign Telephone Survey --- Wave III ---" dated July 2008.

ENERGY AWARENESS

The first objective of the RCEA Program was to determine if an aggressive customer communications program can change levels of residential customer awareness of energy options.

Prior to the campaign, the findings showed 61.5% of the respondents on an unaided basis did recall hearing or seeing some type of energy conservation ad from Hawaiian Electric. This level of recall likely may be attributed to the ongoing advertising conducted by the Company's integrated advertising campaign prior to the commencement of the RCEA Campaign. Since 2005, the Company's advertising messages were developed with elements of both energy awareness and its Demand Side Management program details.

Recall of advertising regarding energy conservation in general increased 20.5 percentage points from the pre-campaign measure in May 2007 to the Wave III post-campaign measure in June 2008, underscoring the successful reach and recall of the RCEA campaign. Oahu residents were asked, *"In the past few months, have you seen or heard any advertising about conserving energy?"* More than four in five respondents in the final Wave III survey said that they had seen or heard advertising about energy conservation (82.0%), compared to three in five respondents in the survey conducted before the campaign was launched (61.5%). Nearly two-fifths among them recalled ads about CFLs, 33.7 points higher than in the baseline measure (37.7% - up from 4.0%), and one-fifth said that they saw ads featuring solar water heaters, 7.2 points higher than in the baseline measure (21.3% - up from 14.1%).



From a combination of questions addressing unaided and aided advertising playback, recall of key campaign messages and elements were gauged below. Playback of messages regarding compact fluorescent lighting (CFLs) and solar water heaters was strong, with each identified by at least seven out of ten respondents. Association of the campaign with Hawaiian Electric was also strong, at 75.6%.

- Rebates for changing the ways you use electricity
- CFLs or compact fluorescent lighting
- Solar water heaters
- ENERGY STAR appliances
- An ad from Hawaiian Electric
- An ad featuring Jade Moon

Based on responses in the Wave III survey, 93.8% of all residents recalled at least one of the six ad messages/elements, compared to 81.9% in the baseline measure. The increases in recall of the individual messages/elements from the baseline to the Wave III survey are dramatic. More than three-fourths of respondents said they remembered ads sponsored by Hawaiian Electric, up 9.8 points from the baseline (75.6% - up from 65.8%). Recall of ads relating to ENERGY STAR appliances increased 26.6 points

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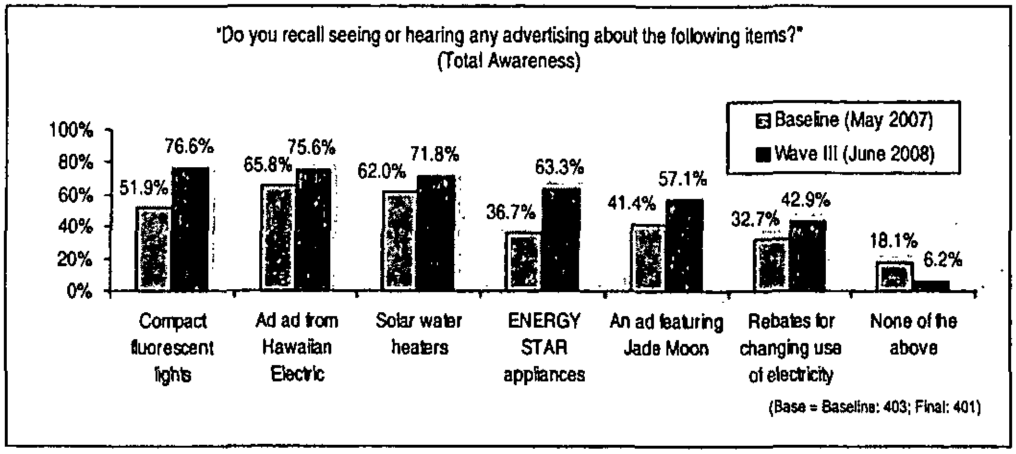
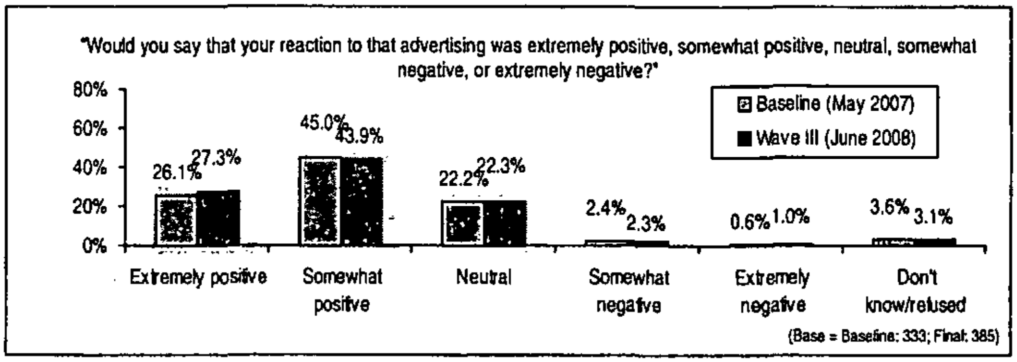
(63.3% - up from 36.7%), while recall of ads featuring CFLs increased 24.7 points (76.6% - up from 51.9%). There were also increases in recall of ads featuring Jade Moon (up 15.7 points to 57.1%), ads for rebates for changing how electricity is used (up 10.2 points to 42.9%), and ads featuring solar water heaters (up 9.8 points to 71.8%).



Reaction to the energy conservation ads (including the six messages/elements from Hawaiian Electric), in general, was positive, with 27.3% of respondents saying that they had an "extremely positive" reaction and another 43.9% saying that they had a "somewhat positive" reaction.



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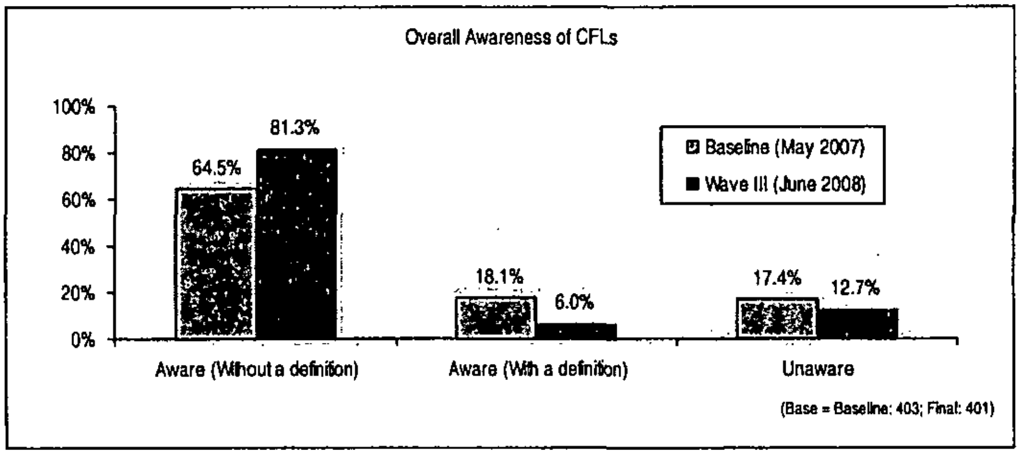
Compact Fluorescent Lights (CFLs)

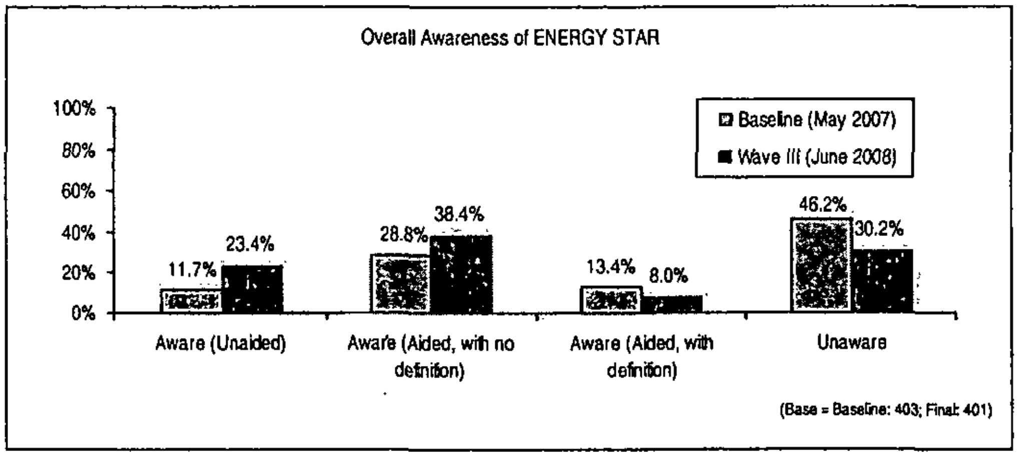
Since the launch of the RCEA campaign, unaided awareness of CFLs (knowledge of CFLs without a definition) increased 16.8 points (81.3% - up from 64.5%), while total awareness increased 4.7 points.



ENERGY STAR

Overall awareness of ENERGY STAR similarly increased since the start of the campaign, from 53.9% to 69.8%. (Note that the proportion of Oahu residents who said that they saw an ad relating to ENERGY STAR nearly doubled after the RCEA campaign was launched, up from 36.7% to 63.3%). Top-of-mind mention of the ENERGY STAR label as an indicator that one appliance is more efficient than another stands at 23.4% (up 11.7 points from 11.7%). After being asked directly, another 38.4% of residents said that they had heard of ENERGY STAR, a 9.6 point increase from the baseline measure. More than one-half among them said that they had seen or heard something about ENERGY STAR in the past three months, a 14.4 point increase from the baseline (53.6%

- up from 39.2%). A near majority of them said that they saw something on TV (53.3% - up from 29.4%).



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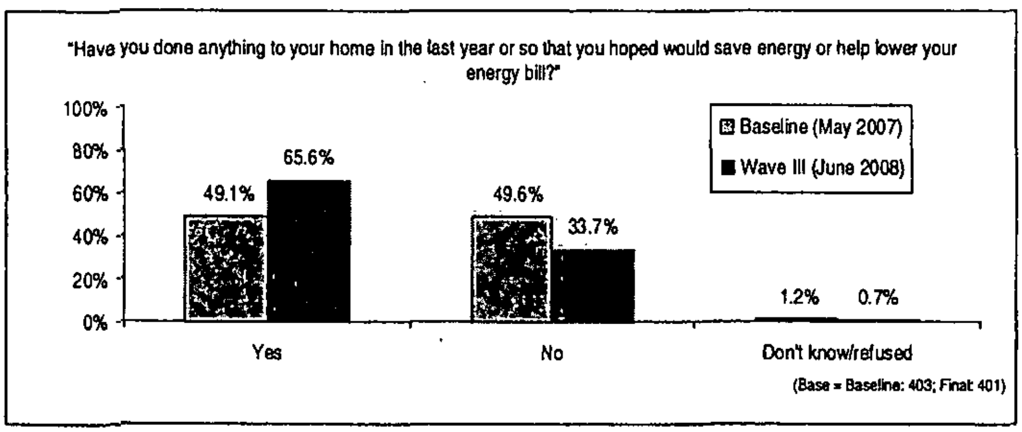
ENERGY CONSERVATION BEHAVIOR

The second objective of the RCEA Program was to see if an aggressive communications program can encourage customers to adopt energy efficient appliances and behavior.

Overall, approximately two-thirds (65.6%) of Oahu residents reportedly did something to their home in the past year that they hoped would save energy or help lower their energy bill. This is a 16.5 point increase from the survey conducted before the RCEA campaign was launched. More than half among them said that they installed compact fluorescent lights (50.6% - up from 32.8%), a 17.8 point increase from the baseline survey. One in four respondents said that they turned off lights or used fewer lights (25.9% - up 3.2 points).



Nearly half of those respondents who said that they had seen or heard energy conservation ads reportedly did something differently in order to conserve energy after seeing or hearing the ad (48.6% - up from 38.1%). This is a 10.5 point increase from the

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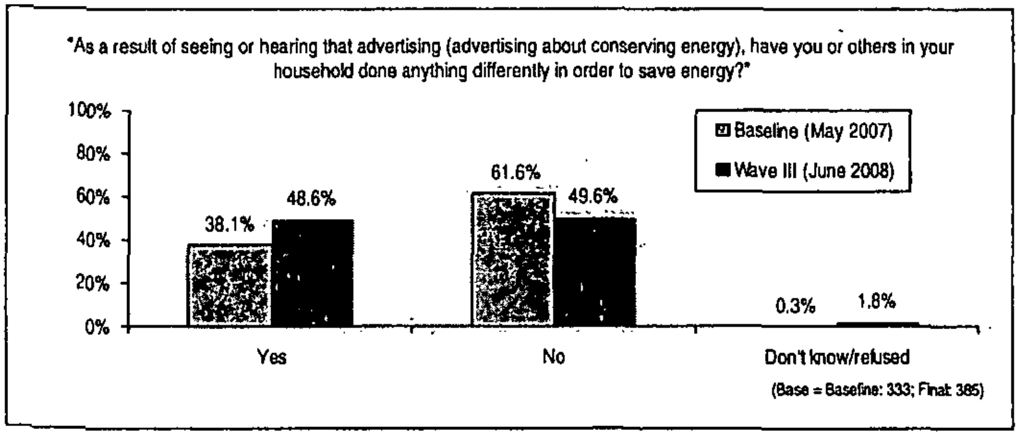
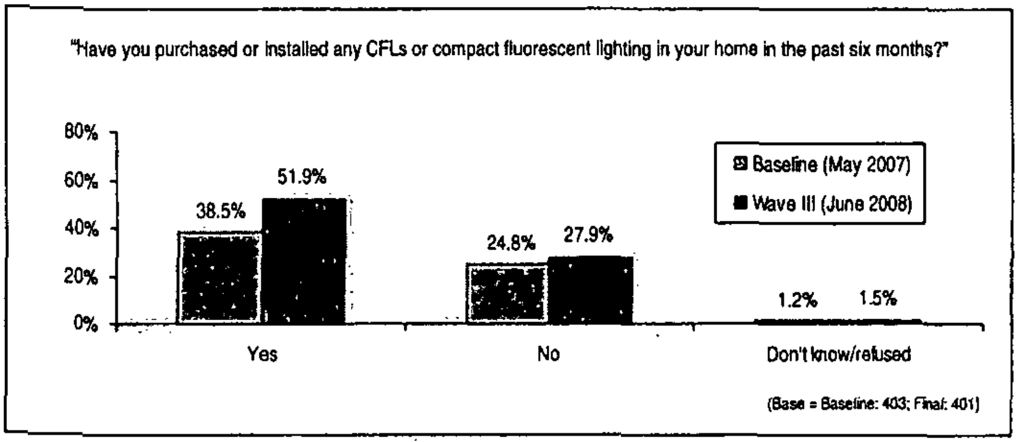
baseline survey conducted before the RCEA Program was launched. Consistent with previous responses, the majority of respondents said that they had installed CFLs (58.3% - up from 38.6%), 19.7 points higher than in the baseline measure. Nearly three-tenths of respondents said that they turned off lights/used fewer lights (28.3% - down 6.3 points) and 15.5% said that they unplugged appliances that they weren't using (15.5% - up 0.5 points).



Overall, more than one-half of residents had reportedly purchased or installed CFLs in their home in the previous six months, 13.4 points higher than in the baseline.



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In the past year, four residents (out of the n=401 in the Wave III sample) reportedly installed ENERGY STAR appliances in their home, in hopes of saving energy or lowering their energy bill. Thirty-one (31) residents in the Wave III survey said that they installed a solar water heating system in the past year; seven installed a solar water heating system directly as a result of seeing or hearing advertising about it.

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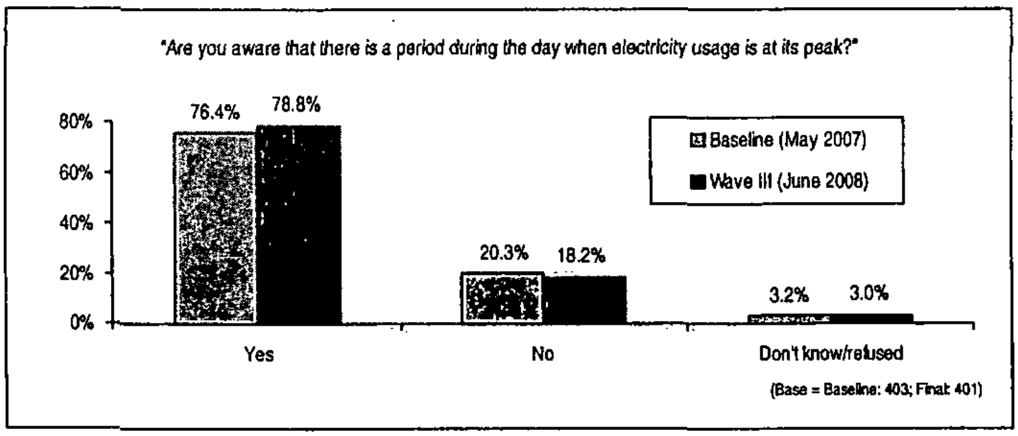
CRITICAL PEAK

Awareness of the critical peak period also increased slightly since the RCEA Program was launched. Awareness of *"a period during the day when electricity usage is at its peak"* increased from 76.4% before the campaign to 78.8% in the final survey. More than seven in ten respondents said that they are aware of things they can do or actions they can take during critical peak periods (72.6% - down 1.6 points). These actions include cutting back air conditioning (28.5%) and turning off lights (28.5%).



While most of those saying they were aware of "a period during the day when electricity usage is at its peak" could identify the early evening hours as that peak, specific knowledge of the 5:00 p.m. to 9:00 p.m. timeframe was very low (4.4% - up 0.5 points). This suggests that further education is necessary.

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HECO RT-19
DOCKET NO. 2008-0083

REBUTTAL TESTIMONY OF ROGER A. MORIN, PH.D.

On Behalf of

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Common Equity

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INTRODUCTION

Q. Please state your name, address, and occupation.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am filing rebuttal testimony on behalf of Hawaiian Electric Company, Inc. ("HECO" or the "Company").

Q. Are you the same Dr. Morin who previously filed testimony in this proceeding?

A. Yes, I am.

Q. Please describe the purpose of your rebuttal testimony.

A. My testimony rebuts the direct testimonies of Mr. Stephen G. Hill (Department of Defense) and Mr. David C. Parcell (Division of Consumer Advocacy) on the cost of capital, filed on April 17, 2009.

Q. Please describe how your rebuttal testimony is organized.

A. My rebuttal testimony is organized in two sections, corresponding to each of the aforementioned individuals. I am also providing the Commission with an updated recommendation in view of the appreciable changes that have occurred in capital markets since I prepared my direct testimony, almost one year ago.

Q. What rate of return on common equity capital ("ROE") do you recommend for the 2009 test year?

A. Based on the results of all my analyses, the application of my professional judgment, the risk circumstances of HECO, and the unsettled current market environment, it is my opinion that a conservative just and reasonable ROE of HECO's electric utility business lies in a range of is 11.00% - 11.25%.

Q. Please summarize the rate of return recommendations of the witnesses you are rebutting in this case.

A. The ROE recommended by each witness I am rebutting in this case is as follows:

Mr. Hill	9.5%
Mr. Parcell	9.5% -10.5%

I note that Mr. Parcell's upper range (10.5%) is within reasonable striking distance of my own updated recommendation of 11.00% - 11.25%, assuming approval of the revenue decoupling mechanisms ("RDM") and in a range of 11.25% - 11.50% without, while Mr. Hill's ROE recommendation is more extreme and outside reasonable limits of probability. I shall therefore devote the bulk of my rebuttal to Mr. Hill's testimony.

REBUTTAL TO MR. HILL'S TESTIMONY

Q. Please summarize the recommended ROE of Mr. Hill.

A. Mr. Hill recommends a ROE for HECO of only 9.50%, which is slightly below the midpoint of Mr. Hill's range of 9.25% – 10.25%. Mr. Hill relies primarily on two Discounted Cash Flow ("DCF") analyses of a group of eleven electric utilities, the first being the traditional constant growth DCF analysis and the second being a two-stage DCF analysis. I note that this is the first time that Mr. Hill has relied on the latter methodology which, not surprisingly, produces lower results than the traditional DCF analysis on which Mr. Hill has always relied upon in the past. As summarized on pages 30 and 32 of his testimony, the two DCF studies produce an estimated ROE of 10.01% and 9.62%, respectively. Mr. Hill performs three checks on his DCF estimate, based on the Modified Earnings Price, Market-to-Book ("M/B"), and Capital Asset Pricing Model ("CAPM") methodologies. Mr. Hill summarizes the results of these checks in table form on page 44. From these various analyses, Mr. Hill also concludes that the ROE for HECO is 9.50%.

Q. Dr. Morin, before you go on with your technical comments on his testimony, what do you make of Mr. Hill's views on capital costs generally?

A. It is difficult to determine Mr. Hill's stance on this issue. On page 10, he correctly notes that government yields have fallen well below the historical range, and on page 11 lines 1-3 he notes that in the current economic environment capital costs are lower, at least judging from the low level of the risk-free rate. But on page 11 line 4, he notes that corporate bond yields have increased since the financial crisis began, and yet on page 13 line 1, he notes that utility bond yields have declined. He then states on page 13 lines 14-27 that there has been an increase in the cost of equity capital and repeats this assertion on page 14 lines 1-2. Then comes the most confusing paragraph of all on page 14 lines 3-8:

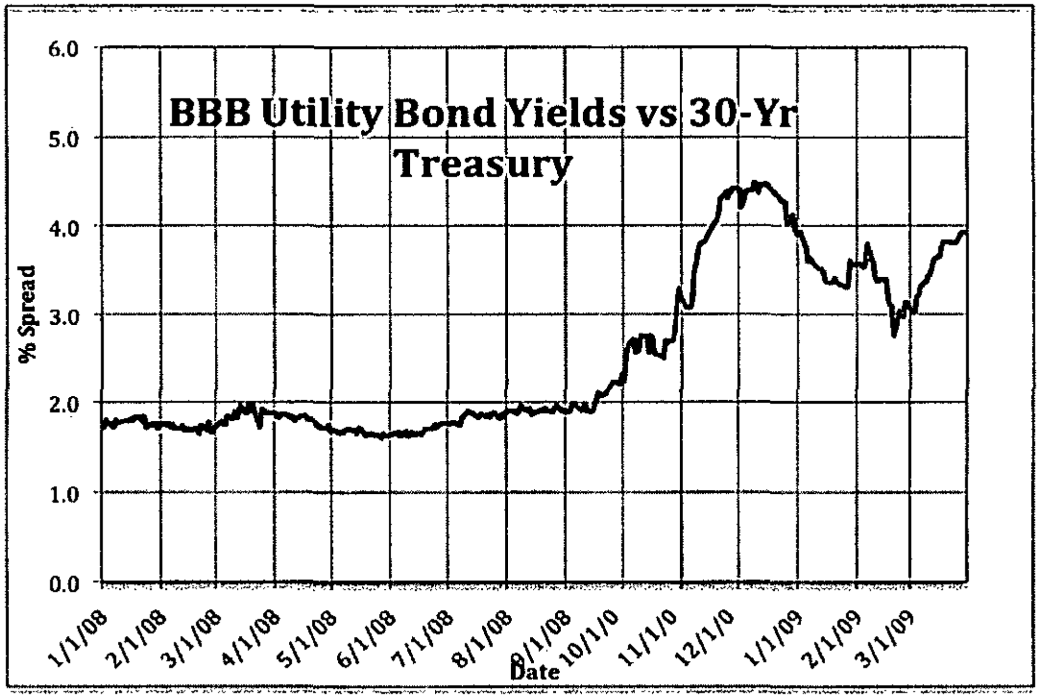
> *Here we have DCF-based data indicating an **increase in equity costs**, along with the fixed-income (bond yield) data discussed above lending credence to the notion that investors' **return expectations have been lowered** somewhat by the recent events in the financial markets. Therefore, it is reasonable to assume from publicly-available data that cost of equity capital is likely to be similar to or **somewhat higher** than it was at mid-year 2008 for electric utilities similar in risk to HECO.*

From these contradictatory statements, I cannot determine whether Mr. Hill believes that capital costs have risen or not.

Q. What is the impact of the ongoing financial crisis on utilities' cost of capital?

A. In a nutshell, it has increased markedly. During the past nine months, capital markets in the U.S. have been more volatile than at any time since the 1930s. Investors have witnessed unprecedented large swings in the stock market and unprecedented corporate interest rate spreads in the debt markets. Many large financial institutions were unable to survive as independent institutions and others have required multi-billion dollar capital infusions.

As shown on the graph below, the spreads between the yields on utility debt and U.S. Treasury securities have increased markedly.



Since the commencement of the financial crisis, single-A yield spreads and BBB yield spreads for utility companies have increased to a level which is some three times higher than the spreads that existed little more than a year ago. In short, increased risk aversion and market illiquidity have resulted in significantly higher borrowing costs for corporations, including HECO. In the current environment, investors' return expectations and requirements for providing capital to the utility industry remain high relative to the longer-term traditional view of the utility industry.

Q. How have regulatory commissions reacted to changing market and industry conditions?

A. Over the past five years, allowed equity returns have generally followed interest rate changes. During 2008, allowed rates did increase from the lowest levels of 2006 and 2007. Of course, these historical averages cannot reflect the recent extreme market volatility. The table below summarizes the overall average ROEs allowed for electric utilities since 2004:

Electric Utility Allowed Returns 2004-2008

	2004	2005	2006	2007	2008
Average Allowed Return	10.75%	10.54%	10.36%	10.36%	10.46%
Average Utility Debt Cost	6.20%	5.67%	6.07%	6.12%	6.65%
Average Risk Premium	4.55%	4.87%	4.29%	4.24%	3.81%

Source: *Regulatory Focus*, SNL Energy Major Rate Case Decisions, January 2009.

Since 2004, the allowed equity risk premiums have ranged from 3.81% to 4.87%. At the low end of this range, based on average single-A utility interest rates for the three months ended March 2009 of approximately 6.3%, the indicated cost of equity is 10.11% (6.30% + 3.81% = 10.11%). At the upper end of this range, the indicated cost of equity is 11.17% (6.30% + 4.87% = 11.17%). One would think that the upper end of the range is most applicable under the current financial crisis conditions. These estimates based on myriad regulatory awards do not even reflect current market turbulence.

Q. Please summarize your specific concerns with Mr. Hill's recommendation.

A. The ROE recommended by Mr. Hill significantly understates an appropriate ROE for HECO for the following reasons:

(i) ***Mr. Hill's recommended ROE for HECO is outside of the mainstream for electric utilities.*** The ROE recommended by Mr. Hill for HECO is well outside the range of currently authorized ROEs for electric utilities in the United States and the zone of currently authorized ROEs for Mr. Hill's own sample of comparable companies.

(ii) ***Mr. Hill uses an ambiguous and arbitrary growth rate for each utility in his DCF analysis***. Mr. Hill's DCF estimates are unreliable because he has selected a growth rate for each company in his comparable group that is ambiguous, arbitrary and impossible to replicate.

(iii) ***Mr. Hill erroneously relies on historical growth rates in his DCF analysis.*** Mr. Hill understates his DCF estimates by erroneously using historical growth rates that have little relevance as proxies for future long-term growth forecasts in the DCF model.

(iv) ***Mr. Hill erroneously relies on dividend growth forecasts in his DCF analysis.*** Mr. Hill understates his DCF estimates by improperly using dividend growth forecasts during a period in which energy utilities are expected to continue to lower their dividend payout ratio over the next several years. Using the appropriate growth rate forecasts, Mr. Hill's DCF estimates increases from 10.0% to 10.8% (exclusive of flotation costs) and 11.1% (inclusive of flotation costs) for his group of electric utilities.

(v) ***Mr. Hill uses the wrong long-term growth rate of the U.S. economy in his two-stage DCF analysis.*** Mr. Hill understates his DCF estimates by using the wrong long-term growth rates of the U.S. economy.

(vi) ***Mr. Hill improperly uses disguised versions of the DCF as "checks" on his DCF analysis and, as a result, are redundant.*** Mr. Hill understates his recommend ROE for HECO because the Modified Earnings Price Ratio and M/B methodologies are disguised versions of the DCF model and do not constitute independent stand-alone checks.

(vii) ***Mr. Hill's recommended ROE improperly ignores flotation costs.*** Mr. Hill understates his recommended ROE by approximately 30 basis points because it does not allow for flotation costs and, as a result, leaves a legitimate expense unrecovered.

(viii) ***The Commission should reject Mr. Hill's claim that HECO is a lower than average risk electric utility.*** The impact of risk-reducing mechanisms called for in the *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* ("Energy Agreement") on the Company's risk profile is reflected to some extent in the capital market data of the comparable companies, and the risk impact of these mechanisms is partially offset by several factors that work in the reverse direction, as explained more fully by Ms. Sekimura in RT-20.

(ix) ***Actuarial data utilized for pension fund accounting are irrelevant in estimating a utility's cost of capital.*** Actuarial data utilized for pension fund accounting are by nature very conservative, consistent with Generally Accepted Accounting Principles ("GAAP") guidelines, and are not suited for assessing the cost of equity capital in a rate proceeding.

Correction of the above-described infirmities would likely increase the ROE recommended by Mr. Hill by at least 150 basis points, from a range of 9.25% – 10.25% to a range of 10.75% – 11.75%.

(i) MR. HILL'S RECOMMENDED ROE FOR HECO IS OUTSIDE OF THE MAINSTREAM FOR ELECTRIC UTILITIES

Q. Dr. Morin, please comment on recent decisions regarding allowed ROEs for vertically integrated electric utilities like HECO.

A. Allowed ROEs, although not a precise indication of a utility's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns. They also serve to provide some perspective on the validity and reasonableness of Mr. Hill's recommended ROE. Using Regulatory Research Associates (now SNL) reported data for ROE decisions rendered for the past twelve months ending in December 2008, the average allowed ROE for electric utilities was 10.5% and approximately 10.7% for integrated utilities like HECO. I note that the majority of those decisions were rendered prior to the current financial crisis during which capital costs for utilities have increased sharply. These ROE decisions are well in excess of Mr. Hill's recommended 9.5%.

Q. Is Mr. Hill's recommended ROE for HECO consistent with the average authorized ROE of the electric utilities in Mr. Hill's comparable group?

A. No, it is not. The AUS Utility Reports survey for May 2009 reports that the average authorized ROE is 10.7% for the combination gas and electric industry and 10.8% for the overall electric utility industry. All but one of the 59 authorized ROEs reported by AUS Utility Reports exceed Mr. Hill's 9.5% recommendation. If we remove the less risky transmission and distribution only ("wires") electric utilities from the AUS sample, the currently authorized returns are higher.

Moreover, Mr. Hill's recommended ROE for HECO is below the authorized ROE of each electric utility in Mr. Hill's comparable group and far below the average authorized ROE of 10.7% for the same group, as shown on the table below. If we eliminate the "wires" companies Northeast Utilities and First Energy from the group, the average allowed ROE is 10.7%.

Mr. Hill's Group of Electric Utilities

	Company Name	Allowed ROE
1	Central Vermont P. S.	10.71
2	FirstEnergy Corp.	10.67
3	Northeast Utilities	9.72
4	American Electric Power	10.71
5	Cleco Corporation	11.25
6	Empire District Electric	10.80
7	Entergy Corp.	10.83
8	Idacorp	10.50
9	Pinnacle West Capital	10.75
10	Unisource Energy	10.13
11	Xcel Energy	10.74
12	Central Vermont P. S.	10.71
13	FirstEnergy Corp.	10.67
AVERAGE		**10.62**
AVERAGE w/o Northeast, First Energy		**10.71**

Source: AUS Utility Reports 05/2009

Although decisions of other regulatory bodies regarding authorized ROEs do not bind this Commission, one cannot overlook the significant difference between Mr. Hill's recommended ROE and the ROEs currently authorized for the electric utility industry.

Q. Is Mr. Hill's ROE significantly lower than other ROEs approved by the Commission?

A. Yes, it is. The ROEs approved by the Commission for Hawaiian Electric utilities in the most recent final decisions are as follows:

	% ROE	Test Yr	Docket No.
HECO	10.70	2005	04-0113
MECO	10.94	1999	97-0346
HELCO	11.50	2000	99-0207

The approved ROEs range from 10.7% to 11.5%. Current capital costs for utilities are at least as high today under unprecedented crisis conditions as they were in prior years when these ROEs were approved .

(ii) MR. HILL USES AN AMBIGUOUS AND ARBITRARY GROWTH RATE FOR EACH UTILITY IN HIS DCF ANALYSIS

Q. What specific DCF methodology does Mr. Hill use to estimate a ROE for HECO equity?

A. Mr. Hill applies a DCF analysis to one sample of eleven electric utilities. Mr. Hill bases the expected dividend yield component on a 6-week average stock price. For the growth component, Mr. Hill examines a broad array of growth rate estimates, including (i) historical and forecast sustainable growth rates, (ii) historical growth rates in book value, earnings, and dividends, (iii) Value Line growth forecasts, and (iv) the consensus growth forecasts reported in Zacks and IBES. This is shown on his Schedules DOD-207 for each company and in summary form on DOD-208 page 2. Mr. Hill then selects a growth rate for each company. However, as I will explain below, his method is arbitrary.

Adding the dividend yield component to the arbitrary growth component selected for each company, Mr. Hill produces a DCF estimate of 10.0% for the group of electric utilities.

Q. Did you attempt to replicate Mr. Hill's DCF analysis for a specific company to illustrate Mr. Hill's methodology?

A. Yes, I did, but I was unable to replicate the analysis. Mr. Hill selects American Electric Power ("AEP") as his "case study" to derive his DCF growth rate forecast and cites the following growth rate estimates for AEP as reported on page 2 of Schedule DOD-207 and page 2 of Schedule DOD-208:

AEP Growth Proxies	Estimate	Reference
5-yr historical sustainable	5.10%	DOD-207 page 2
2008 sustainable	4.88%	DOD-207 page 2
2009 sustainable	5.29%	DOD-207 page 2
projected sustainable 2011-13	5.18%	DOD-207 page 2
5-yr historical Book Value	0.00%	DOD-208 page 2
5-yr historical Dividend	-9.00%	DOD-208 page 2
5-yr historical Earnings	-0.50%	DOD-208 page 2
5-yr Compound Hist Book Value	6.30%	DOD-208 page 2
5-yr Compound Hist Earnings	3.12%	DOD-208 page 2
5-yr Compound Hist Dividends	-0.12%	DOD-208 page 2
VL Projected dividend	4.00%	DOD-208 page 2
VL Projected earnings	5.00%	DOD-208 page 2
VL projected Book Value	6.00%	DOD-208 page 2
analyst IBES projection	5.38%	DOD-208 page 2
analyst Zacks projection	5.50%	DOD-208 page 2

On page 24 lines 24-25, Mr. Hill declares that he uses the five-year average sustainable growth rate of 5.2% for AEP as a <u>benchmark</u> against which he measures the company's growth rate trends. Yet, from this array of growth rate estimates, Mr. Hill arbitrarily selects, with little formal substantiation, a DCF internal growth rate forecast of 5.0%. It is unclear how the benchmark of 5.2% squares with the final choice of a 5.0% internal growth rate.

Q. Were you able to determine how Mr. Hill arrives at a DCF growth rate forecast of 5.0% for AEP?

A. No. The average of the growth rates displayed above for AEP is 3.1%, the median is 5.0%, and the midpoint of the range is -1.4%. I was unable to replicate or decipher how Mr. Hill arrived at a 5.0% growth rate forecast from this vast list of growth rates. As shown below, the most meaningful growth proxies for electric utilities' growth rates are the analysts' growth projections in the range of 6.3% – 7.3% reported on Mr. Hill's Schedule DOD-208 page 2.

Q. Were you able to determine how Mr. Hill arrives at a DCF estimate of 9.63% for AEP?

A. No. On Schedule DOD-207, Mr. Hill asserts that the DCF estimate of ROE for AEP is 10.88%, the sum of a dividend yield of 5.84% plus a growth rate forecast of 5.04%. Mr. Hill derives the growth rate forecast of 5.04% directly from the last column of page 1 of Schedule DOD-208, which computes the sustainable growth rate forecast ($g = br + sv$) for AEP as the sum of a sustainable internal growth rate (5.00%) and a sustainable external growth rate (0.04%).

Q. How does Mr. Hill arrive at a sustainable internal growth rate of 5.00% and an external growth rate of 0.04% for AEP?

A. It is unclear how Mr. Hill arrived at these two growth rates. The "internal growth" and "external growth" figures are presumably derived from the upper panel of page 2 of Schedule DOD-207, under the headings "internal growth" and "external growth." The internal growth rate of 5.00% cannot be found anywhere on the upper panel of page 2 of Schedule DOD-207 for AEP. The sustainable internal growth rate of 5.0%, however, is contained within the qualitative narrative of AEP's sustainable growth rate in Mr. Hill's Schedule DOD-203 page 2, and is arbitrarily characterized as "reasonable".

In short, from a vast array of some fifteen growth estimates, Mr. Hill arbitrarily selects a growth rate forecast of 5.04% for AEP with little quantitative support or academic empirical evidence as to the optimal growth rate proxy in the DCF model.

Q. Were you able to replicate Mr. Hill's growth rate forecasts for any of the companies contained in Mr. Hill's sample?

A. No. I was unable to replicate Mr. Hill's final choice of growth rate estimates of any utility in Mr. Hill's sample of electric utilities from the vast array of growth rate estimates provided in Schedule DOD-208. The growth estimates simply appear without scientific foundation, derivation or ability to be replicated.

Q. What is the sustainable growth rate technique used by Mr. Hill to implement the DCF model?

A. Mr. Hill appears to rely heavily on the so-called sustainable (a.k.a. internal) growth method. *See* pages 24-26 and Schedules DOD-207 and DOD-208 in his direct testimony. In the sustainable growth method, the growth rate forecast is based on the equation g = b(ROE), where b is the percentage of earnings retained and ROE is the expected rate of return on book equity (ROE). Mr. Hill also accounts for the impact of external stock financing on growth by adding an external growth term (g = sv).

Q. Is the sustainable growth methodology an appropriate technique to implement the DCF model in this proceeding?

A. No. The sustainable growth methodology used by Mr. Hill in this proceeding contains a logical contradiction because the method requires an explicit assumption on the ROE expected from the retained earnings that drive future growth. Mr. Hill bases his ROE estimate on (i) achieved ROEs in the past five years 2003-2007 and (ii) Value Line forecast ROEs for 2008, 2009, and the 2011-2013 period.

In brief, Mr. Hill's implementation of the sustainable growth method, to the extent relied upon, is logically circular because it *assumes* a ROE in a regulatory process that is *designed to estimate* the fair and reasonable ROE.

Q. Is the sustainable growth rate technique consistent with empirical evidence?

A. No. Empirical finance literature demonstrates that the sustainable growth rate technique is a very poor explanatory variable of market value and is not correlated significantly to measures of value, such as stock price and price/earnings ratios.

Q. Are the Value Line estimates of ROE and retention ratio representative of the market consensus?

A. No, not necessarily. Mr. Hill's exclusive reliance on Value Line forecasts of ROE and retention ratio runs the risk that such forecasts are not representative of investors' consensus forecast. Moreover, the forecasts of the expected ROE published by Value Line are based on end-of-period book equity rather than on average book equity. The following formula adjusts the reported end-of-year values so that they are based on average common equity, which is the common regulatory practice:

$$ra = rt \frac{2\,Bt}{Bt + Bt\text{-}1}$$

Where: ra = return on average equity

rt = return on year-end equity as reported

Bt = reported year-end book equity of the current year

Bt-1 = reported year-end book equity of the previous year

This one error alone – failing to use average common equity - understates Mr. Hill's DCF estimates by approximately 10-20 basis points, depending on the magnitude of the book value growth rate forecast.

(iii) MR. HILL ERRONEOUSLY RELIES ON HISTORICAL GROWTH RATES IN HIS DCF ANALYSIS

Q. Please discuss the use of historical growth rates in applying the DCF model to energy utilities.

A. Although it is not clear as to what weight Mr. Hill accords historical growth rates given the arbitrary nature of his final choice of growth estimates, Mr. Hill considers historical growth rates in arriving at proxies for the DCF growth forecast component. It may be reasonable to assume that historical growth rates in dividends/earnings influence investors' assessment of the long-run growth rate forecast of future dividends/earnings if the company and industry are stable. Because of structural changes in the energy industry, however, historical growth rates have little relevance as proxies for long-term growth forecasts. Moreover, historical growth rates are largely redundant because such historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model.

(iv) MR. HILL ERRONEOUSLY RELIES ON DIVIDEND GROWTH FORECASTS IN HIS DCF ANALYSIS

Q. Should the Value Line dividend growth forecasts be considered in applying the DCF model to electric utilities?

A. No. There are two serious problems with the use of Value Line dividend growth forecasts. First, heavy reliance on Value Line growth forecasts runs the risk that such forecasts are not representative of investors' consensus forecast. Second, it is inappropriate to use dividend growth forecasts of energy utilities at this time in the DCF model. The Value Line dividend growth forecasts are largely dominated by the anticipated dividend performance over the next few years and higher business risk. The intermediate growth rate in dividends cannot equal the long-term growth rate when the dividend payout ratio is expected to change because projected dividend growth and earnings growth must adjust to the changing payout ratio. This "problem" is not unique to analysts' earnings growth forecasts and is also inherent in the use of historical growth rates to forecast growth rates.

Reliance on "near-term" dividend growth is improper because first it is expected that energy utilities will continue to lower their dividend payout ratios over the next several years in response to increased business risk. Second, in the current environment where utilities, including HECO, are increasing their capital expenditures, dividends cannot be expected to grow at the same rate that investors expect earnings to grow.

Therefore, earnings and dividends are not expected to grow at the same rate in the future. Mr. Hill's own growth rate data on Schedule DOD-208 page 2 demonstrate this phenomenon because both historical and projected utility dividend growth rates are less than the earnings growth rate forecast. As discussed in my direct testimony, the use of consensus analysts' earnings growth forecasts in the DCF model mitigates this potential bias—an approach supported by empirical literature.

Q. What does the published academic literature say on the subject of analysts' growth rate forecasts in the DCF model?

A. Published studies in the academic literature demonstrate that (i) analysts' growth rate forecasts are reasonable indicators of investor expectations and (ii) investors rely on such forecasts. Cragg and Malkiel present detailed empirical evidence that (i) the average analysts' growth rate forecast is a better predictor of investor expectations than are historical growth rates; (ii) the average analysts' growth rate forecast represents the best possible source of

DCF growth rate forecasts; and (iii) historical growth rates do not contain any information not already included in analysts' growth rate forecasts.[1] Other studies confirm the superiority of analysts' growth rate forecasts over historical growth extrapolations.[2]

Q. What do you conclude from Mr. Hill's DCF growth rate analysis?

A. Although Mr. Hill reports and discusses historical growth rates and dividend growth rate forecasts, it is difficult to discern from the discussion of each company's growth rate to what extent, if any, Mr. Hill relies on historical growth rates and dividend growth rate forecasts reported by Value Line. To the extent Mr. Hill relies on either of historical growth rates and Value Line's dividend growth forecasts, he does so in error.

One would expect that averages of analysts' earnings growth forecasts, such as those contained in IBES, First Call, Reuters, or Zacks, are more reliable estimates of the investors' consensus expectations than either historical growth rates or one particular firm's dividend growth forecast. As discussed in my direct testimony, the empirical finance literature has demonstrated that consensus analysts' growth forecasts (i) are reflected in stock prices, (ii) possess a high explanatory power of equity values, and (iii) are used by investors.

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[1] Malkiel Burton & John Cragg, *Expectations and the Structure of Share Prices* (1982).

[2] James Vander Weide & Willard Carleton, "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management* (Spring 1988); Stephen Timme & Peter Eisemann, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," *Financial Management* (Winter 1989).

Moreover, it is necessary to use earnings forecasts rather than dividend forecasts because of the extreme scarcity of dividend forecasts compared to the availability of earnings forecasts. Given the paucity and variability of dividend forecasts, use of dividend forecasts produces unreliable DCF results.

Use of the analyst growth forecasts would have generated an average growth rate forecast in the range of 5.7% - 7.6% for Mr. Hill's sample group of electric utilities,[3] not the 4.9% average used, as shown on the first column of numbers on Mr. Hill's Schedule DOD-208 page 2. Even if we take the minimum growth rate forecasts of 5.7% instead of Mr. Hill's arbitrary 4.9%, Mr. Hill's DCF estimate increases by 80 basis points, from 10.0% to the 10.8% (exclusive of flotation costs) and 11.1% (inclusive of flotation costs) for his group of electric utilities.

(v) MR. HILL USES THE WRONG LONG-TERM GROWTH RATE OF THE U.S. ECONOMY IN HIS TWO-STAGE DCF ANALYSIS.

Q. Is Mr. Hill's two-stage DCF analysis consistent with his past practices?

A. No. Over the years, Mr. Hill has always performed a traditional DCF analysis in most, if not all, of his testimonies for electric utilities in retail jurisdictions and has never relied on the two-stage DCF model to the best of my knowledge. This is the first time, I believe.

[3] See Hill Schedule DOD-208 page 2. The average analysts' growth forecasts are 5.73% from Value Line, 7.58% from IBES, and 6.3% from Zacks.

Q. Do you agree with Mr. Hill's two-stage DCF analysis?

A. No, I do not. Mr. Hill implements a two-stage DCF analysis that produces a ROE estimate of 9.62%, as shown on Schedule DOD-211 and on his summary table of results on page 44 of his testimony. Although I certainly agree with the validity of the two-stage DCF methodology, I disagree with the key input data Mr. Hill uses in the second growth stage—the long-term growth estimate. Mr. Hill bases the latter on the Congressional Budget Office's ("CBO") long-term GDP growth forecast of 4.2% for the U.S. economy over the period 2009-2019.

Q. Do you agree with that estimate?

A. No. First of all, Mr. Hill's 4.2% forecast is inconsistent with the long-term historical growth of the economy of 6.94% that he calculates on his own Schedule DOD-205. Second, Mr. Hill has cherry-picked the 4.2% forecast shown on Table 2-6 of the January 2009 edition of the CBO's economic projections and failed to mention that right alongside the CBO forecast of 4.2% is the Blue Chip forecast of 5.1% and the Administration's forecast of 4.9%.

Third, Mr. Hill should have compared the utility growth rate forecasts with the historical long-term growth of the economy as a whole and/or the long-range growth forecasts in GDP projected for the very long-term. The former has been approximately 6%, 6.94% according to Mr. Hill's Schedule DOD-205, while the latter is in the 5.5% - 6.0% range.[4] Mr. Hill's comparison

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[4] A long-term forecast of nominal growth in GDP can be formulated by combining a long-term inflation estimate (2.0% - 2.5% according to the CBO projections) with a long-term real growth rate forecast of

to a short-term growth rate forecast (the next ten years) is inappropriate because the growth term of the DCF model is perpetual in nature.

In short, Mr. Hill's second-stage growth forecast of 4.2% for his comparable group of electric utilities slightly understates the long-term expected GDP nominal growth by at least 130 basis points (5.5% - 4.2% = 1.3%).

Q. How would Mr. Hill's DCF results change if the appropriate long-term GDP growth forecast were used in the two-stage DCF analysis?

A. Use of the GDP long-term growth forecast of 5.5% in Mr. Hill's second-stage DCF analysis instead of the medium-term forecast of 4.2% would raise Mr. Hill's DCF estimates by 130 basis points, from 9.62% to 10.92%.

(vi) MR. HILL IMPROPERLY USES DISGUISED VERSIONS OF THE DCF AS "CHECKS" ON HIS DCF ANALYSIS

Q. Does Mr. Hill employ checks on his DCF results?

A. Yes. As one of his checks on the DCF results, Mr. Hill employs the Modified Earnings-Price Ratio method. According to this method, the return of earnings to shareholders is the cost to the company of equity funds, and the same rate of return must be earned on equity-financed assets to equal the cost rate.

Q. Is the modified earnings-price ratio method an appropriate check of DCF results?

A. No. The corporate finance literature in the 1960s extensively discussed the Earnings-Price Ratio methodology that lies at the root of Mr. Hill's Modified

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3.5%, and the long-term expected GDP nominal growth is 5.5% - 6.0%.

Earnings-Price Ratio method. Indeed, the Earnings-Price Ratio method enjoyed some brief notoriety in regulatory proceedings during that period.

Today, however, the Earnings-Price Ratio method has vanished from use because it produces unreliable results. In fact, the Earnings-Price Ratio method constitutes an accurate measure of the cost of equity (and collapses into the standard constant-growth DCF model) only under two very limited circumstances:

(1) the firm must pay all earnings out in dividends, and

(2) the firm must be an "ordinary" firm, (i.e., a company without profitable opportunities earning a return on new investments equal to the cost of equity).

Neither of these circumstances is present here, and therefore the Commission should reject Mr. Hill's Modified Earnings-Price Ratio. Furthermore, the Modified Earnings-Price Ratio, like the retention growth method discussed above, is logically circular because it requires an assumed ROE, which is the very quantity the model is trying to estimate.

I am unaware of any financial witness or regulatory body that has relied on this antiquated methodology.

Q. Is Mr. Hill's modified earnings-price ratio methodology any different from the earnings-price ratio methodology?

A. No, it is not. The two methodologies are equivalent. The relationship between the Earnings-Price Ratio and the Modified Earnings-Price Ratio can easily be seen from Mr. Hill's testimony page 39 line 22 to page 40 line 10. Elton and

Gruber (Modern Portfolio Theory and Investment Analysis, New York University, Wiley & Sons, New York, 1995, pp. 401-404) posit the following formula,

$$k = (1-b)E/(1-cb)P$$

where "k" is the cost of equity capital, "b" is the retention ratio, "E" is earnings, "P" is market price and "c" is the ratio of the expected return on equity to the cost of equity capital (ROE/k). Because the process of regulation sets the return on equity equal to the cost of equity, that is, ROE is set equal to "k" by the regulator, "c" equals 1.0 in the above formula. Thus k = E/P, and the two methodologies are equivalent.

Q. Does Mr. Hill employ a check other than the modified earnings-price ratio of his DCF results?

A. Yes. Mr. Hill also uses the M/B ratio to check his DCF results.

Q. Is the M/B ratio methodology an appropriate check of DCF results?

A. No. On page 42 lines 2-4, Mr. Hill admits that the M/B ratio methodology "*is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method.*" Furthermore, the M/B ratio, like both the retention growth method and the Modified Earnings-Price Ratio discussed above, is logically circular because it requires an assumed ROE, which is the very quantity the model is trying to estimate.

(vi) MR. HILL'S CAPM RESULTS SHOULD BE GIVEN VERY LITTLE, IF ANY, WEIGHT.

Q. Does Mr. Hill employ a CAPM estimate to check his DCF results?

A. Yes. As a check on his DCF estimate, Mr. Hill performs a CAPM analysis of ROE summarized on Schedule 8.

Q. Is Mr. Hill correct that the results of a CAPM analysis are less reliable than those from a DCF analysis?

A. Yes, he is. I share Mr. Hill's misgivings on the reliability of the CAPM at this time.

Q. How much weight should be accorded to the CAPM results under current market circumstances?

A. I believe little, if any, weight should be accorded to the CAPM results under present economic circumstances for three reasons. First, the CAPM estimates in the single-digit are barely above the corporate cost of debt and are therefore suspect. Second, because the betas employed in the CAPM analysis are estimated over five-year historical periods, the impact of the ongoing financial crisis is not yet fully captured in the five-year historical betas. Third, government interest rates have decreased substantially following the Federal Reserve's expansionary policies designed to jumpstart the stalled economy, thus lowering the CAPM results. At the same time, the cost of corporate debt and the cost of equity for electric utilities have increased significantly, as evidenced by the record high corporate yield spreads, and by the DCF results for utilities that have increased by some 150-200 basis points in response to lower stock prices (higher dividend yields) following the financial crisis.

This anomaly between actual market costs and the estimation techniques used in this proceeding puts the Company at significant financing risk. As such, much less weight should be accorded to this method at present. There is a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all market participants, including HECO.

For all these reasons, considerably less weight, if any, should be placed on CAPM results. In the interest of brevity and expediency, and given that both Mr. Hill and I agree that very little weight, if any, should be accorded to the CAPM results, I shall refrain from commenting on Mr. Hill's CAPM results.

(vii) MR. HILL'S RECOMMENDED ROE IMPROPERLY IGNORES FLOTATION COSTS

Q. What allowance for flotation costs does Mr. Hill make with respect to his recommended ROE for HECO?

A. Mr. Hill fails to include any allowance whatsoever for flotation costs in his recommended ROE for HECO. Mr. Hill's DCF estimates are therefore downward-biased by approximately 30 basis points as a result of that omission. Moreover, Mr. Hill's testimony is inconsistent with regard to flotation costs. In a discussion of sustainable growth in the DCF model on page 26 lines 15-16, Mr. Hill recognizes that "investor expectations regarding growth from external source (sales of stock) must be considered and examined." Indeed, Mr. Hill quantifies the effect of such issues on company growth in his Exhibit DOD-207 under the heading "external growth."

Finally, Mr. Hill's disregard of flotation costs is inconsistent with (i) Value Line forecasts that show that electric utilities will be issuing new common stock in the future, and (ii) Mr. Hill's own exhibit, which demonstrates that Mr. Hill's "comparable" groups are scheduled to issue considerable amounts of new equity. See Exhibit DOD-207, pages 1-5, under the heading "external growth" for 2008, 2009 and 2011-2013.

Q. Why should the authorized ROE be adjusted to include an allowance for flotation costs?

A. Flotation costs represent the discounts that must be provided to place new securities in the issues of new equity. Flotation costs have a direct and an indirect component. The direct component represents monetary compensation to the security underwriter for (i) marketing/consulting services, (ii) the risks involved in distributing the issue, and (iii) any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue (frequently referred to as "market pressure").

Flotation costs for common stock are analogous to the flotation costs associated with past bond issues, which, as a matter of routine regulatory policy, continue to be amortized over the life of the bond, even though no new bond issues are contemplated. Flotation costs for common stock are not amortized because such securities have no finite life. Therefore, the recovery of flotation cost requires an upward adjustment to the authorized ROE by dividing the expected dividend yield component of the DCF model by (1 - f), where "f" is the flotation cost factor.

Q. Does Mr. Hill explain why he does not provide an allowance for flotation costs in his recommended ROE for HECO?

A. Mr. Hill offers four spurious reasons as to why he fails to include an allowance for flotation costs.

First, Mr. Hill erroneously asserts that flotation costs on common stocks are analogous to bonds sold at a premium to par value (i.e., the company's cost of debt is less than the coupon rate). See page 45, lines 2-20. In practice, the calculation of the embedded cost of debt accounts for issuance costs and premiums or discounts at the time of issue, and recognizes sinking fund and call provisions. This is because premiums or discounts and flotation costs influence the effective yield to the investor and cost to the utility and are typically allowed to be recovered by regulators.

Unlike bonds, however, a utility's book equity account is credited by the net proceeds of a common stock issue after issuance costs and not by the gross proceeds. In other words, the common stock investment recorded on the balance sheet, unlike bond issues, is less than the amount of money actually put up by the investor by the amount of issuance costs, regardless of whether the net issue price is less than, equal to or greater than book value. If the investor is to earn the required return on a reduced book equity base, the allowed return needs to exceed the required return by an amount sufficient to cover the discrepancy between gross and net proceeds from a common stock issue. Moreover, unlike bonds, the allowed ROE is the market, or current, return and not the embedded cost of debt.

Q. What is the second rationale provided by Mr. Hill regarding his omission of flotation costs?

A. Mr. Hill argues on page 45 line 29 to page 46 line 2 that "the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at or below its book value." This argument, however, fails to address the simple fact that, in issuing common stock, a company's common equity account is credited by an amount less than the market value of the issue. Therefore, the company must earn slightly more on its reduced rate base to produce a return equal to that required by shareholders. The stock's M/B ratio is irrelevant because flotation costs are present, irrespective of whether the stock trades above, below, or at book value.

Q. What is the third rationale provided by Mr. Hill regarding his omission of flotation costs?

A. Mr. Hill on page 46, lines 6-12 then argues that the majority of the flotation costs are not out-of-pocket expenses incurred by the issuing utility and, as such, should not be recovered. This argument, if taken to a logical conclusion, would suggest that depreciation expenses associated with the construction of plant should not be recovered because depreciation expenses are not out-of-pocket expenses.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. The expense and recovery of flotation costs would burden current ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. Moreover, as discussed in my pre-filed direct testimony, common stocks, unlike bonds, have no finite life over which flotation costs could be amortized. Therefore, the most appropriate method to recover flotation costs is via an upward adjustment to the authorized ROE.

Mr. Hill then makes the circular argument on page 46, lines 13-20 that the flotation cost allowance is unwarranted because investors factor these costs in the stock price. Such circular reasoning could be used to justify any regulatory policy, regardless of the propriety of the policy. For example, under Mr. Hill's reasoning, it would be appropriate to authorize a clearly confiscatory ROE, such as of 1%, because investors would reflect this return in the stock price.

Q. What is the fourth rationale provided by Mr. Hill regarding the omission of flotation costs?

A. Mr. Hill's fourth argument on page 46 lines 21-22 is that "*research has shown that a specific adjustment for issuance expenses is unnecessary.*" In support of this assertion, Mr. Hill cites a sole source - an "unpublished note" in a relatively obscure bulletin. Indeed, Mr. Hill's statement stands in sharp contrast to (i) most finance textbooks and (ii) the myriad articles published in academic journals documenting and quantifying the flotation cost allowance. Please see Appendix B of my direct testimony for a review of this considerable literature.

(viii) THE COMMISSION SHOULD REJECT MR. HILL'S CLAIM THAT HECO IS A LOWER THAN AVERAGE RISK ELECTRIC UTILITY

Q. Do you agree with Mr. Hill's view that the Commission should shift its view of HECO as an above-average risk utility to one that, with the Energy Agreement, has lower than average risk?

A. No, I do not, and nor does the investment community. The Company's bond ratings remain at BBB, which is approximately the industry average.

I do not share Mr. Hill's opinion that HECO's "strong" business risk profile designation by S&P necessarily implies that its business risk is stronger, weaker, or identical to the industry average because the "strong" designation applies to very few utilities. The "excellent" designation on the other hand characterizes most utilities. According to S&P, 143 of the 186 utilities possess the "excellent" appellation. The "excellent" designation is intended to show that relative to other industries, the utility industry generally possesses an excellent business risk profile. S&P's previous Business Risk Scores ranging from 1 to 10 were superior in that regard; HECO's business score of 5 indicated that the Company had an average business risk. It should also be pointed out that credit ratings are not directly related to required equity returns. There is little evidence of a causal relationship between credit quality and required or observed equity returns in the utility industry. Finally, in relative terms, it is difficult to argue that HECO's business risk profile is even "strong," given the depressed state of the regional economy and the upcoming Energy Agreement-related challenges. My own belief is that HECO's investment risk has diminished from above average to average, assuming that the risk-mitigating aspects of the Energy Agreement are approved.

On pages 6-7, Mr. Hill correctly points out that several aspects of the Energy Agreement lower the Company's operating risk, namely revenue decoupling, pension fund trackers, energy infrastructure surcharges, ability to seek construction work-in-progress ("CWIP") treatment, and the energy cost adjustment clause ("ECAC"). While I agree that these mechanisms reduce risk on an absolute basis, they do not necessarily do so on a relative basis, that is, compared to other utilities. For example, the ECAC does not reduce relative risk since most electric utilities in the industry are under some form of energy cost adjustment mechanism. The approval of adjustment clauses, ROE incentives riders, trackers, forward test years, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond rating and business risk scores. The fact remains that the Company's credit ratings are slightly below average and remain fragile.

While adjustment clauses, riders, and cost tracking mechanisms may mitigate (on an absolute basis but not on a relative basis) a portion of the risk and uncertainty related to the day-to-day management of HECO's operations, there are other significant factors to consider that work in the reverse direction for HECO, for example: (i) the weakening of the Hawaii economy, (ii) the Company's dependence on a huge capital spending program requiring external financing, (iii) weak financial metrics, (iv) uncertain feasibility and unknown costs of the Energy Agreement plans, and (v) regulatory risks, given that details of major provisions of the Energy Agreement have yet to be determined. These additional factors, ignored by Mr. Hill, largely offset the presence of the aforementioned risk-mitigating mechanisms.

My own view is that any risk-mitigating impact that the risk-reducing Energy Agreement-related mechanisms could have on the Company's risk profile is reflected to some extent in the capital market data of the comparable companies, and that the risk impact of these mechanisms is partially offset by several factors that work in the reverse direction. The proof is in the pudding in that the Company's bond ratings compare to the industry average despite the presence of such mechanisms.

(ix) ACTUARIAL DATA UTILIZED FOR PENSION FUND ACCOUNTING ARE IRRELEVANT IN ESTIMATING A UTILITY'S COST OF CAPITAL.

Q. Did you detect any logical inconsistency in Mr. Hill's recommended ROE for HECO?

A. Yes, I did. On pages 51-52 of his testimony, Mr. Hill tests the reasonableness of his 9.50% recommended ROE by comparing it to expected stock market returns of 9.25% that are implied in utility pension fund actuarial data, notably

Northeast Utilities' retirement portfolio. Mr. Hill concludes that his proposed cost of equity of 9.25% is not only consistent with such data but it is conservative. This is incorrect for several reasons.

The return figures cited by Mr. Hill are for the total equity market. HECO and utilities generally are less risky than the overall market. HECO's beta is 0.72 according to Mr. Hill, meaning that HECO is 72% as risky as the overall stock market, and, therefore, should have a lower expected return than the overall market. Yet, Mr. Hill's recommended ROE for HECO exceeds the aforementioned range of expected return for the market as a whole. This is patently illogical. In order to be consistent with his view of stock market returns of 9.25% and with HECO's beta of 0.72, Mr. Hill should have recommended a ROE of 6.7%, that is 0.72 times 9.25%. That result is preposterous, of course, as it is below the cost of debt for BBB utilities.

Q. Is actuarial data relevant in estimating the cost of equity capital?

A. No, it is not. Mr. Hill tests the reasonableness of his recommended ROE of 9.50% by comparing this recommendation to expected stock market returns of 9.25% that he claims are implied in pension fund actuarial data. This comparison, in the context of a rate proceeding, is highly unusual. I cannot recall any cost of capital witness comparing an individual utility's ROE to its pension fund's actuarial data. Additionally, I am unaware of any regulatory commission that has relied on such data. Indeed, the California Public Utilities Commission recently considered similar arguments and concluded as follows:

> The objectives of a pension fund are fundamentally different from that of an equity investor in a single utility and the risk profiles are not comparable. The Employee Retirement Income Security Act dictates that pension funds must be diversified whereas a utility's ROE is based on risks specific to that utility's operations.
>
> More importantly, pension fund returns are related to market value of assets held in the pension fund while a utility's ROE is applied to a book value rate base. This difference can best be illustrated by dividing an average pension fund return by PG&E's market-to-book ratio. Based on ATU's 9.62% calculated average pension fund return and DRA's market-to-book ratio of 1.9 for PG&E, PG&E would only need to earn a 5.06% ROE on its rate base to equal the 9.62% average pension fund return. However, a 5.06% ROE is 116 basis points below its long-term debt cost, effectively eliminating PG&E's ability to support its credit and to raise the equity necessary to fulfill its public utility responsibilities as required by Bluefield and Hope. Pension return assumptions are not comparable to the ROE used in utility ratemaking. Having resolved this issue, PG&E should not be required to continue comparing its pension return assumptions to its ratemaking ROE in future ROE proceedings.
>
> *In re S. Cal. Edison Co.*, 262 P.U.R. 4th 53, 72 (Ca. Pub. Utils. Comm'n. 2007).

Q. Do you find the reasoning of the California Public Utilities Commission convincing?

A. Yes. Actuarial data utilized for pension fund accounting are by nature very conservative, consistent with GAAP guidelines, and are not well suited for assessing the cost of equity capital in a rate proceeding. By virtue of the very long-term nature of pension fund assets, projected returns on pension fund assets are not indicative of the cost of equity in the context of a regulatory proceeding. Moreover, the actuarial data on which Mr. Hill relies--namely one particular corporate actuary's assumptions (Northeast Utilities)--is highly selective.

Q. Are actuarial pension fund projected returns based on arithmetic or geometric averages?

A. The actuarial pension data arbitrarily selected by Mr. Hill are based on geometric mean returns rather than on arithmetic mean returns because of the very long-term nature of pension fund assets. As discussed later in my rebuttal testimony, only arithmetic means are appropriate for forecasting and estimating the cost of capital.

Q. What else is wrong with Mr. Hill's reliance on pension fund actuarial data and financial advisors' estimates?

A. The return figures cited by Mr. Hill are market returns and not book returns. The manner in which the regulator applies market-based returns to book equity understates the cost of equity under current capital market conditions. Application of market-based returns produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B ratio is close to unity. Application of market-based returns to equity book values does not account for the investor's expected return when the M/B ratio of a given stock deviates from unity. The reason for the distortion is that the market-based return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base. The return given to equity investors is lower than what they actually require when M/B ratios exceed unity. This is neither equitable for the existing stockholders nor efficient from the point of view of attracting capital to cover the significant capital expenditures that need to be undertaken.

In short, this Commission, like the California Public Utilities Commission, should ignore Mr. Hill's views on the applicability of actuarial pension returns and individual financial advisory returns in determining a utility's allowed ROE.

Q. What do you conclude from Mr. Hill's recommended ROE?

A. Mr. Hill understates the appropriate ROE for HECO. The following table summarizes the principal reasons why Mr. Hill's DCF-based recommended ROE understates an appropriate ROE for HECO:

Source	**Basis Points**
Flotation Cost Allowance	30
Sustainable Growth Calculation	20
Analysts Growth Rate Forecasts	80

Correction of these understatements would increase Mr. Hill's recommended ROE based upon his traditional DCF study, the mainstay of his recommendation, from 10.0% to 11.3%, which is comparable to my own recommendation. Moreover, Mr. Hill's two-stage DCF results increase to nearly 11% from using the proper long-term GDP growth rate.

Q. Would the adoption of Mr. Hill's recommended ROE endanger HECO's credit quality?

A. Yes, it certainly increases the probability of a deterioration in HECO's credit quality. Extreme decreases in HECO's authorized ROE, such as the decreases recommended by Mr. Hill, could alarm the investment community, lower stock price, and threaten HECO's credit ratings. A weakening of HECO's credit ratings, stock price, and earnings power at a time when the HECO needs to attract significant external capital on reasonable terms is ill-advised in the current crisis environment of turmoil and uncertainty.

RESPONSES TO MR. HILL'S CRITICISMS

INTEREST RATES

Q. Do you agree with Mr. Hill that interest rates have fallen since you prepared your direct testimony?

A. Yes, I do. On page 57 of his testimony, Mr. Hill argues that interest rates have fallen by 110 basis points since I prepared my direct testimony, and that my CAPM estimates are therefore too high. While I agree that government interest rates have decreased since I prepared my direct testimony, the cost of corporate debt and the cost of equity for electric utilities have increased, as evidenced by the DCF results for electric utilities that have increased significantly by some 100 basis points in response to lower stock prices (higher dividend yields) following the financial crisis.

Capital markets remain in a state of turmoil. As a result, the cost of money for corporations has increased, and new debt/stock issues are limited to the highest-quality borrowers. The debt markets have witnessed record high yield spreads (the incremental yield over Treasury rates needed to issue debt) and a more severe differentiation between the spreads charged to companies with different credit ratings.

BETA ESTIMATES

Q. Do you agree with Mr. Hill that betas have fallen since you prepared your direct testimony?

A. Yes, I do, and my updated recommendation recognizes this fact. On page 58, Mr. Hill points out that betas have fallen from the 0.80 level to the 0.70 level since I prepared my direct testimony in May 2008. However, I note that betas are estimated based on five-year historical periods and that the impact of the ongoing financial crisis is not yet fully captured in the five-year historical betas. As I mentioned above, there is a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all market participants over the next 18-24 months at least.

MARKET RISK PREMIUM

Q. How do you respond to Mr. Hill's reference to a PowerPoint slide presented by Professor Marston to buttress his claim that the prospective market risk premium has declined relative to historical measures?

A. On pages 59-60 of his testimony, Mr. Hill argues that the reference to the Harris-Marston research in my direct testimony on the magnitude of the prospective market risk premium ("MRP"), namely 7.2%, has been superseded by a PowerPoint slide in a presentation made by Professor Marston in 2007. Mr. Hill reproduces the slide on page 60 of his testimony.

Reliance on a PowerPoint slide to support Mr. Hill's contention that the MRP has shrunk in recent years does not provide the kind of analysis that would allow this Commission to make a reasonable determination of the appropriate MRP. A PowerPoint slide is a highly questionable source of information in assessing an appropriate risk premium for a regulated utility and in gauging the academic state of the art in the field of finance. Moreover, I am not aware that the Harris-Marston updated findings have been published in any peer-reviewed academic journal.

EMPIRICAL CAPM

Q. Please comment on Mr. Hill's assessment of the empirical CAPM used in your testimony.

A. On pages 16-20 of his direct testimony, Mr. Hill erroneously asserts that use of "adjusted" betas with an Empirical CAPM analysis "double-counts the effect of changing the slope of the capital market line." Contrary to such suggestion, the Empirical CAPM is not an adjustment (increase or decrease) in beta. Instead, the Empirical CAPM is a formal recognition of the fact that empirical evidence demonstrates that the observed risk-return tradeoff is flatter than predicted by the CAPM.

The Empirical CAPM and the use of adjusted betas comprise two separate features of asset pricing. Assuming *arguendo* a company's beta is estimated accurately, the CAPM will still understate the return for low-beta stocks. Furthermore, if a company's beta is understated, the Empirical CAPM will also understate the return for low-beta stocks. Both adjustments are necessary.

The graph on page 44 of my direct testimony demonstrates that the Empirical CAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

With respect to the empirical validity of the plain vanilla CAPM, empirical studies of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM have supported the conclusion that (i) beta is related to security returns, (ii) the risk-return tradeoff is positive, and (iii) the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as predicted by CAPM. In other words, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn returns somewhat less the CAPM would predict.

In sum, a plain vanilla CAPM will understate the return required for low-beta securities and overstate the return required for high-beta securities. The Empirical CAPM refines the plain vanilla CAPM to account for this phenomenon.

DCF DIVIDEND YIELD

Q. Is Mr. Hill's criticism that you multiplied the spot dividend yield by one plus the expected growth rate (1 + g) warranted?

A. No. The basic annual DCF model ignores the time value of quarterly dividend payments and assumes dividends are paid once a year at the end of the year. Because the appropriate dividend to use in a DCF model is the prospective dividend for all companies that have positive growth rate forecasts, the dividend for all companies should be increased by the (1 + g) factor. Multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments and understates the expected return on equity. Use of this method is conservative in the sense that the annual DCF model ignores the more frequent compounding of quarterly dividends.

Q. Does Mr. Hill multiply the spot dividend yield by one plus the expected growth rate (1 + g)?

A. Yes. Mr. Hill multiplies the spot dividend yield by one plus the expected growth rate (1 + g) for those companies expected to raise their quarterly dividends in the second quarter of calendar year 2009.

Q. Did you double-count the expected dividend yield for growth?

A. No. Contrary to assertions of Mr. Hill at pages 54 and 63 of his testimony, I did not overstate the dividend yield by double-counting the dividend increase. This is because I used the "current dividend yield" as defined by Value Line in the Value Line Investment Analyzer software and then grossed up the current dividend yield to produce the expected dividend yield required by the DCF model.

DCF GROWTH RATES

Q. Is reliance on analysts' earnings growth forecasts in the DCF model problematic?

A. No, it is not. On page 64 of his testimony, lines 1-6, Mr. Hill erroneously asserts as follows with respect to my exclusive use of analysts' earnings growth forecasts in the DCF:

> *...exclusive reliance on earnings growth, absent any examination of the underlying fundamentals of long-run growth, can lead to inaccurate equity cost estimates. For example, reliance on projected earnings growth in a situation in which projected earnings were expected to recover from reduced levels would include (in any DCF estimate) the assumption that equity returns will increase at the same exaggerated rate every five years into the indefinite future.*

In other words, the intermediate growth rate in dividends cannot equal the long-term growth rate when the dividend payout ratio is expected to change because projected dividend growth and earnings growth must adjust to the changing payout ratio. This "problem" is not unique to analysts' earnings growth forecasts and is also inherent in the use of historical growth rates to forecast growth rates.

Reliance on "near-term" dividend growth is improper because it is expected that energy utilities will continue to lower their dividend payout ratios over the next several years in response to increased business risk and the need to alleviate reliance on external financing. Therefore, earnings and dividends are not expected to grow at the same rate in the future. Mr. Hill has conveniently supplied growth data on Schedule DOD-208 page 2 of his testimony. The growth rate data clearly demonstrate this phenomenon because projected utility dividend growth rate forecasts (4.1%) are less than the earnings growth rate forecast (7.6%). As discussed in my direct testimony, I used consensus analysts' earnings growth forecasts in the DCF model to mitigate potential bias—an approach supported by empirical literature.

Q. Is your growth rate analysis "mechanistic in that it simply plugs selected projected data into a formula to produce a growth rate with no underlying analysis of either the historical or projected growth rate fundamentals," as Mr. Hill suggests?

A. No, it is not. Contrary to this statement on page 63 of Mr. Hill's testimony, lines 22-25, my direct testimony devotes several pages to an analysis of historical growth rates and analysts' growth forecasts. Given this analysis, Mr. Hill's statement that I undertook "no underlying analysis of either the historical or projected growth rate fundamentals" is patently false.

Mr. Hill continues on page 63, lines 24-25 to state that "Dr. Morin, in his own published work, warns against this type of analysis." This is a clear example of Mr. Hill selectively citing materials out of context. The passage cited by Mr. Hill immediately precedes the following section of my book:

> A note of caution is also necessary when dealing with historical growth rates and their use in the DCF model. Historical growth rates can be downward biased by the impact of diversification and restructuring activities and by the impact of abnormal weather patterns in the case of energy utilities. Acquisitions, start up expenses, and front end capital investments associated with diversification and restructuring efforts, and unfavorable weather patterns can retard and dilute historical earnings growth, and such growth is not representative of a company's long term growth potential. Therefore, caution must be exercised when applying any of the growth estimating techniques directly to recent historical utility company data.
>
> Given a dramatic change in a utility's operating environment, the need to be forward looking is apparent. Historically based

> measures of risk and growth can be downward biased in assessing present circumstances... The fundamental risks and growth prospects of electric utilities are also changing rapidly following the passage of the Energy Bill in 1993. These shifts in growth prospects take some time before they are fully reflected in the historical growth rates. Hence, backward looking growth and statistical analysis may fail to fully reflect the fact that the risks and growth prospects of utilities have escalated, and may only provide limited evidence that the risk and the cost of capital to these utilities have increased. Of course, the converse may also be true under certain circumstances.
>
> Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital* at pages 237-38 (1st ed. 1994) (emphasis added).

Indeed, the same chapter contains an entire section that comprehensively discusses the hazards of relying on historical growth rates.

Q. What does the published academic literature say on the subject of analysts' growth rate forecasts in the DCF model?

A. As I discussed earlier in my rebuttal testimony, published studies in the academic literature demonstrate that (i) analysts' growth rate forecasts are reasonable indicators of investor expectations, and (ii) investors rely on such forecasts.

Q. Mr. Hill criticizes your DCF analysis because it relies on earnings growth projections and he believes that such forecasts are overly optimistic. How do you respond?

A. On page 64 of his testimony, Mr. Hill denounces the use of financial analysts' earnings forecasts on the grounds that such forecasts are overly-optimistic. I disagree, at least for utility stocks. Using virtually all publicly available analyst earnings forecasts for a large sample of companies (over 23,000 individual forecasts by 100 analyst firms), Lys and Sohn show that stock returns respond to individual analyst earnings forecasts, even when they are closely preceded by earnings forecasts made by other analysts or by corporate accounting disclosures.[5] Using actual and IBES data from 1982-1995, Easterwood and Nutt regress the analysts' forecast errors against either historical earnings changes or analysts' forecasting errors in the prior years.[6] Results show that analysts tend to under-react to negative earnings information, but overreact to positive earnings information.

The more recent studies provide evidence that analysts make biased forecasts and misinterpret the impact of new information.[7] For example, several studies in the early 1990s suggest that analysts either systematically underreact or overreact to new information. Easterwood and Nutt discriminate between these different reactions and reported that analysts underreact to negative information, but overreact to positive information. The recent studies do not necessarily contradict the earlier literature. The earlier research focused on whether analysts' earnings forecasts are better at forecasting future earnings than historical averages, whereas the recent literature investigates whether the

[5] Thomas Lys & Sungkyu Sohn, "The Association Between Revisions of Financial Analysts' Earnings Forecasts and Security Price Changes," *Journal of Accounting and Economics* 13, 341-363 (1990).

[6] John Easterwood & Stacey Nutt, "Inefficiency in Analysts' Earnings Forecasts: Systematic Misreaction or Systematic Optimism?" *The Journal of Finance* 54: 1777-1797 (1999).

[7] Other relevant papers corroborating the superiority of analysts forecasts as predictors of future returns versus historical growth rates include: Dan Fried & Dov Givoly, "Financial Analysts Forecasts of Earnings: A Better Surrogate for Earning Expectations," *Journal of Accounting and Econometrics* 85-107 (1982); R. Charles Moyer, *et al.*, "The Accuracy of Long-Term Earnings Forecasts in the Electric Utility Industry" *International Journal of Forecasting*, 1, 241-252 (1985); and David Gordon, "Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management* 15, 50-55 (1989).

analysts' earnings forecasts are unbiased estimates of future earnings. It is possible that even if the analysts' forecasts are biased, they are still closer to future earnings than the historical averages, although this hypothesis has not been tested in the recent studies. One way to assess the concern that analysts' forecasts may be biased upward is to incorporate into the analysis the growth forecasts of independent research firms, such as Value Line, in addition to the analyst consensus forecast. Unlike investment banking firms and stock brokerage firms, independent research firms such as Value Line have no incentive to distort earnings growth estimates in order to bolster interest in common stocks.

Mr. Hill argues that analysts tend to forecast earnings growth rates that exceed those actually achieved and that this optimism biases the DCF results upward. The magnitude of the optimism bias for large rate-regulated companies in stable segments of an industry is likely to be very small. Empirically, the severity of the optimism problem is unclear for regulated utilities, if a problem exists at all. It is interesting to note that Value Line forecasts for utility companies made by independent analysts with no incentive for over- or understating growth forecasts are not materially different from those published by analysts in security firms with incentives not based on forecast accuracy, and may in fact be more robust.

MARKET-TO-BOOK (M/B) RATIOS

Q. Is Mr. Hill correct in his claims that there are inconsistencies in your published works regarding the DCF model and market-to-book ratios?

A. No. In his testimony, on page 65, lines 12-17, Mr. Hill argues that the 1984 edition of my book (twenty-five years ago) did not criticize the ability of the DCF model to accurately estimate the cost of equity depending on the M/B ratio of utilities. Similarly, Mr. Hill asserts the following:

> Dr. Morin's first text on the cost of capital, Utilities' Cost of Capital, was published in 1984, and was conceived and written *during a time period for utilities in which interest rates were very* high and market prices were generally below book value. ....There is no indication in Dr. Morin's 1984 text that when market prices are below book value (as they were at that time), the DCF overstates the cost of equity (as is now Dr. Morin's claim).

Mr. Hill fails to recognize, however, that the ability of the DCF model to estimate the cost of equity accurately depending on the M/B ratio of utilities was simply not an issue for utilities a quarter century ago because utilities were trading at market prices very close to book value. Similarly, it was not an important issue when Professor Gordon developed the DCF model in the mid-1960s. Instead of reaching back some 25 years, perhaps Mr. Hill should have consulted the 1994 and 2006 editions of my book,[8] each of which discusses at length the chronic inability of the DCF model to accurately estimate investor returns when Market-to-Book ratios deviate markedly from unity.

Q. Is Mr. Hill's contention that your views on the applicability of the DCF have changed since 1984 correct?

A. No. Mr. Hill has once more distorted my views and cited passages from my 1984 book out of context. Mr. Hill falsely asserts that there is no reference to

[8] *See* Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, chapter 10 (1st ed. 1994);

the DCF understating the cost of equity in my 1984 text when Market-to-Book ratios are below one. In late 1984 when the book was published, M/B ratios were at nearly 1.0. Indeed, M/B ratios have been well above 1.0 for over twenty years.

The reference to the understatement of the cost of equity when M/B ratios are slightly below one referred to the dilutive effects of issuing stock below book value and the necessity of allowing for flotation cost.

Q. How do you respond to Mr. Hill's discussion of your numerical example regarding the reliability of DCF estimates?

A. On pages 67-68 of his testimony, Mr. Hill digs out a numerical example from a Puget Sound Energy rebuttal and concludes on page 68 that this particular numerical example does not show that the DCF understates the cost of equity when the M/B ratio exceeds 1.0. Mr. Hill appears to be confused on this subject. First, the allowed return of 10% is not assumed to be determined by the DCF, as claimed by Mr. Hill on page 68, line 27. Such an assumption would be circular. The allowed return of 10% is assumed to be determined exogenously by the CAPM or the Risk Premium method, for example.

The numerical example is quite simple despite Mr. Hill's attempts to confuse the issue. A stock is trading at $100 and the investor requires a 10% return, so that $10 of earnings are needed. But the regulatory body applies the 10% return to a $50 book value. So, there are only $5 of earnings available to the investor, and the realized return is only 5%. It is that simple.

Roger A. Morin, *The New Regulatory Finance: Utilities' Cost of Capital*, ch.12 (1st ed. 2006).

To pursue the analogy provided by Mr. Hill at page 69 of his testimony, imagine a broker trying to sell to an investor with a return requirement of 10% a utility stock priced at $100 per share and whose M/B ratio is 2.0. The broker would say to the investor: "I've got a stock for you that's going to pay a 10% return on a $50 book value – in other words one share will get you $5 but each share has to drop from $100 to $50 in order for the price to drop to book value. Are you interested?" No rational investor would pay $100 for a stock that is going to drop to $50. In short, the analogy defies logic.

Q. Do you agree with Mr. Hill's criticism of your comparable group?

A. No, I do not. On page 55 of his testimony, Mr. Hill argues that the risk of my second group of electric utilities is not comparable to my first group of electric utilities. I disagree, for both groups had almost identical betas of 0.87 when I prepared my direct testimony.

REBUTTAL TO MR. PARCELL'S TESTIMONY

Q. Please summarize Mr. Parcell's ROE recommendation.

A. Mr. Parcell recommends that a return allowance in a range of 9.5% - 10.5% be employed on the common equity capital of HECO. In determining HECO's cost of equity, Mr. Parcell applies a DCF analysis to three groups of electric utilities. For the growth component of his DCF analysis, he uses a blend of analysts' growth forecasts, historical growth rates, and the earnings retention method. From his DCF estimates, summarized on page 38 of his testimony, Mr. Parcell concludes that the DCF estimate of HECO's cost of equity lies in a range of 10.0% - 11.0%.

Mr. Parcell also applies a CAPM analysis to the same three groups of companies, using long-term Treasury bond yields as proxies for the risk-free rate and Value Line beta estimates. He seems to place little, if any, weight on the CAPM results of 7.5%, as they are barely above the Company's cost of debt, if at all.

Lastly, Mr. Parcell performs a Comparable Earnings analysis on a sample of utilities and a sample of unregulated industrial companies.

From these various analyses, Mr. Parcell concludes that HECO's cost of common equity capital lies in the range of 9.5% - 10.5%. Mr. Parcell proposes a ROE at the lower end of his proposed range to reflect the lower risk associated with the decoupling mechanism.

Q. Please summarize your specific concerns with Mr. Parcell's testimony.

A. I have nine concerns:

1. Stale Stock Price. Mr. Parcell's use of the 3-month period ending February 2009 to calculate average stock prices in his DCF analysis ignores the impact of decreased stock prices over that 3-month period. The impact of the ongoing current financial crisis that began in early October continues to place upward pressure on required returns. Capital costs have exploded upward in the past 9 months and remain high. Using current stock prices that reflect the impact of the ongoing financial crisis on capital costs and its devastating impact on utility stock prices raises Mr. Parcell's DCF estimate by 45 basis points from this factor alone.

The financial risks and, therefore, the cost of capital, have increased substantially for all firms, including utilities.

2. Understated Dividend Yield. Mr. Parcell's dividend yield component is understated because it is not consistent with the annual form of the DCF model. It is inappropriate to increase the dividend yield by adding one-half of the future growth rate (1 + ½ g) to the spot dividend yield. The appropriate manner of computing the expected dividend yield when using the basic annual DCF model is to add the full growth rate rather than one-half of the growth rate. This adjustment also allows for the failure of the annual DCF model to allow for the quarterly timing of dividend payments. This error understates the DCF results by some 20 basis points.

3. DCF Retention Growth. The retention growth method for estimating the growth component of the DCF calculation is suspect because one is forced to assume the answer to implement the method. From Mr. Parcell's own evidence, investors expect substantially higher returns for utilities than what he recommends.

4. DCF Growth Rates. Analysts' Forecasts. Investors are expecting substantially higher growth rates than Mr. Parcell's growth rates for the sample companies. Using analysts' consensus growth forecasts increases the DCF estimate of the cost of common equity by 130 basis points (1.30%).

5. CAPM Weight. For reasons discussed earlier, CAPM results should be accorded little, if any, weight.

6. CAPM Risk-Free Rate. Mr. Parcell's risk-free rate proxy is stale since it relies on the average yield on 20-year Treasury bonds over a 3-month period instead of the current yield on 20-year Treasury bonds. Yields on long-term Treasury securities have escalated substantially over the 3-month period. Using the appropriate risk-free rate, Mr. Parcell's CAPM estimates must be raised by 20 basis points for this correction alone.

7. CAPM Market Risk Premium ("MRP"). There are conceptual blemishes in Mr. Parcell's three MRP proxies.

8. Downward ROE Adjustment. I disagree with the magnitude of Mr. Parcell's downward ROE adjustment in order to account for the risk-mitigating impact of the decoupling mechanism.

9. Mr. Parcell's criticisms of my testimony are largely unfounded.

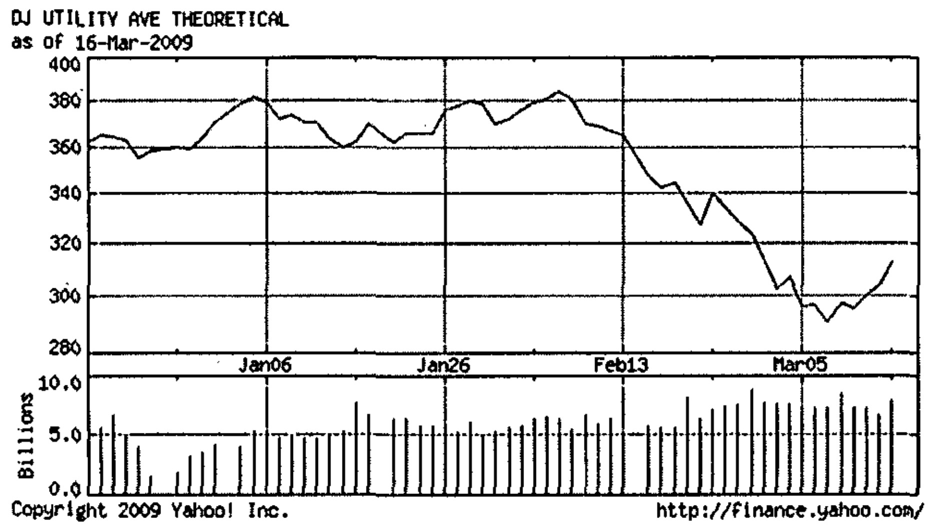
1. STALE STOCK PRICES

Q. Are the stock prices used by Mr. Parcell in his DCF analysis current?

A. No, they are not. Mr. Parcell relies on average stock prices over the three-month period December 2008 – February 2009. These stock prices are stale. Using current stock prices instead of 3-month old prices in Mr. Parcell's DCF analysis, the average DCF estimates increase by approximately 35 basis points.

Q. What is the impact of using current stock prices on Mr. Parcell's DCF results?

A. Set forth below is a graph that replicates the recent price movements of the Dow Jones Utility Average over the 3-month period used by Mr. Parcell in his DCF analysis. Utility stocks have dropped from the 370 level to the 310 level, that is, more than 15% over that 3-month period. Yet, Mr. Parcell's reliance on a 3-month average index stock price of 340 [(370+310/2)] ending February 2009 ignores this substantial change in equity market conditions. The practical effect is that his stock prices are overstated by approximately 7.5%.



Source: http://chart.financc.yahoo.com/c/6m/ / dju

Using current stock prices instead of stock prices averaged over three months ending February 2009 in Mr. Parcell's DCF analysis, the average DCF estimate of Mr. Parcell's proxy group of companies increases by 45 basis points.[9]

Q. What is the impact of using more current stock prices on Mr. Parcell's final ROE recommendation?

A. In his final summary of results shown in table form on page 49 of his testimony, Mr. Parcell's DCF results of 10.0% - 11.0% increase by 45 basis points and become 10.5% - 11.5%. Since Mr. Parcell places little weight in

[9] Mr. Parcell reports a dividend yield (D/P) of approximately 5.5% for his three groups of companies on Exhibit CA-403 page 3. Since utility stock prices are currently 7.5% lower relative to the 3-month average, they stand at 92.5% of their previous level, the updated dividend yield becomes 5.5/0.925 = 5.95, an increase of 45 basis points.

his final recommendation on the outlying CAPM results shown on that table, we are left with the DCF results of 10.5% and 11.5% and the Comparable Earnings results of 9.5% - 11.5%. I submit that a range of 10.0% - 11.0% with a midpoint of 10.5% is quite consistent with these updated results. In other words, from these amended results, it is clear that Mr. Parcell should have at least recommended the upper end of his range from this fact alone.

2. DIVIDEND YIELD

Q. Please discuss Mr. Parcell's dividend yield component in the DCF model.

A. The annual DCF model states very clearly that the expected rate of return on a stock is equal to the expected dividend at the end of the year divided by the current price of the stock, plus the expected growth rate. Thus the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Mr. Parcell understates the dividend yield by halving it. Mr. Parcell uses a spot dividend yield inflated by one-half of the expected dividend growth, $Do(1 + 1/2\ g)$, rather than the correct expected dividend yield that is inflated by one full year of growth, $Do(1 + g)$.

This mathematical adjustment fails to measure the full dividend flow expected by the investor and underestimates the cost of equity by approximately 20 basis points. For example, for a spot dividend yield of 5% and a growth rate of 5%, Mr. Parcell's estimated dividend yield is $5\%(1 + .05/2) = 5.1\%$. The correct dividend yield to employ is $5\%(1 + .05) = 5.3\%$, which is about 20 basis points higher.

3. DCF RETENTION GROWTH

Q. Please describe Mr. Parcell's methodology for specifying the growth component of the DCF model.

A. As summarized on page 36 of his testimony, Mr. Parcell employs five proxies as a proxy for the expected growth component of the DCF model: 1) historical earnings retention ratio, 2) projected earnings retention ratio, 3) five-year historical growth rates in dividends, earnings, and book value, 4) projected growth rates in dividends, earnings, and book value, and 5) analysts' forecasts of EPS growth as reported in First Call.

Q. Can you comment on Mr. Parcell's earnings retention growth estimate in the DCF model?

A. Earlier in my rebuttal of Mr. Hill, I discussed the conceptual and empirical infirmities of the retention growth method. I believe that the results from its use should be given little, if any, weight.

4. DCF GROWTH RATES

Q. Are the historical growth rates of electric utilities reliable proxies for expected future growth?

A. No, they are not. Mr. Parcell uses historical growth rates in dividends, earnings, and book value as proxies for expected growth, as shown in the first three columns of Exhibit CA-408 page 3. If historical growth rates are to be representative of long-term future growth rates, they must not be biased by non-recurring events. This is certainly the case for electric utilities, where growing competition, diversification programs, acquisitions, restructurings and write-off activities have exerted a dilutive effect on historical earnings and dividends. In such cases, it is obvious that analysts' growth forecasts provide a more realistic and representative growth proxy for what is likely to happen in the future than historical growth. In any event, historical growth rates are somewhat redundant given that analysts formulate their growth expectations based in part on historical patterns. I note that more than one third of all the historical growth rates shown in the first three columns of Schedule CA-408 page 3 are negative, which is quite contrary to the constant perpetual positive growth assumption that underlies the DCF model.

In conclusion, Mr. Parcell's historical growth rates should be given considerably less weight, if any.

Q. Do you see any dangers in relying on Value Line as an exclusive source of forecasts in applying the DCF model?

A. Yes, I do. As discussed earlier, one would expect that averages of analysts' growth forecasts such as those contained in First Call and/or Zacks, rather than one particular firm's forecast, are more reliable estimates of the investors' consensus expectations likely to be impounded in stock prices.

Q. What does the published academic literature say on the subject of growth rates in the DCF model?

A. As discussed earlier, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts.

Q. Are investors expecting growth rates equal to Mr. Parcell's range?

A. No. The best evidence shows that investors are expecting growth rates higher than Mr. Parcell has found. For his first group of electric utilities, Mr. Parcell has found (see upper panel of Schedule CA-408 page 4) growth rates ranging from 3.1% to 6.2%, with a mean of 4.3%. As indicated earlier, the retention growth estimate should be discarded from the analysis and historical growth rates should be given considerably less weight, which leaves us with the Value Line growth forecast of 4.3% and the consensus analyst forecast of 6.2%, that is a range of 4.3% - 6.2% (midpoint 5.2%). The midpoint result is 90 basis points (0.9%) above Mr. Parcell's median estimate of 4.3%. This understatement alone causes Mr. Parcell's DCF cost of equity estimates for this first group of companies to be downward-biased by 90 points even without factoring in the appropriate expected dividend yield component. To different degrees, the same is true for Mr. Parcell's DCF estimates for the second and third group of companies, which are also downward-biased by similar amounts.

Q. Please comment on Mr. Parcell's criticism of your DCF analysis.

A. On page 63 of his testimony, Mr. Parcell takes issue with the fact that I have used only one indicator of growth in the DCF analysis, namely, analyst growth projections and that I have ignored historical and projected growth rates in dividends and book value. In my direct testimony, I discussed the impropriety of relying on "near-term" dividend growth because: 1) earnings growth drives dividend growth, 2) of the scarcity of dividend forecasts, and 3) it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years in response to increased business risk and external financing requirements, and that earnings and dividends are not expected to grow at the same rate in the future. In my direct testimony and earlier in my rebuttal, I also discussed the merits of using consensus analysts' earnings growth forecasts in the DCF model and the supportive empirical literature.

5. CAPM WEIGHT

Q. How much weight should be accorded to the CAPM results under current market circumstances?

A. As I discussed at length earlier, I believe considerably less weight should be accorded to the CAPM results under present economic circumstances. To the extent that Mr. Parcell has accorded any weight to his CAPM results, and I do not believe that he did, he should have recommended a ROE at the upper end of his range. If the Commission were to accord any weight to Mr. Parcell's CAPM results, the following comments on Mr. Parcell's CAPM analysis are germane.

6. CAPM RISK-FREE RATE

Q. Do you agree with Mr. Parcell's risk-free rate proxy in his CAPM analysis?

A. No, I do not, because it is stale. As a proxy for the risk-free rate, Mr. Parcell uses 3.49% which is the average yield on 20-year Treasury bonds for the 3-month period December 2008 – February 2009. The latest Value Line issue (May 8, 2009) reports a yield of 4.0% on 30-year Treasury bonds, an increase of 50 basis points.

Q. Do you agree with Mr. Parcell's beta estimates in his CAPM analysis?

A. Yes, I do.

7. CAPM MARKET RISK PREMIUM

Q. How does Mr. Parcell estimate the MRP component of the CAPM?

A. In order to determine the MRP component of his CAPM analysis, Mr. Parcell relies on three estimates. First, he examines the difference between the accounting returns on book equity (ROE) on the S&P 500 Index companies group over the 1978-2007 period and the contemporaneous level of 20-year Treasury bond yields. The average spread (MRP) is 6.45%. Second, he relies on the long-term 5.6% historical MRP reported in the Ibbotson Associates Valuation 2009 Yearbook for the 1926-2008 period based on arithmetic averages. Third, he relies on the long-term 3.9% historical MRP reported in the same publication for the same period but this time based on geometric averages. From these three estimates, Mr. Parcell concludes that the MRP is 5.32%, that is, the average of the three MRP estimates. I seriously disagree with these estimates for several reasons.

Q. Do you agree with Mr. Parcell's first estimate of 6.45% for the MRP in his CAPM analysis?

A. I do not agree with this first estimate. Mr. Parcell has combined *accounting book returns* on equity for the S&P 500 companies with *market returns* on long-term U.S. Treasury bonds in order to arrive at his first estimate of the MRP. In a classic apples and oranges situation, Mr. Parcell has mismatched accounting (book) returns with market (economic) returns.

Q. *Do you agree with Mr. Parcell's second estimate of 5.6% for the MRP in his CAPM analysis?*

A. No, not quite. For his second MRP proxy, Mr. Parcell used a historical risk premium of 5.6%. This estimate is drawn from Ibbotson and Associates (now Morningstar) in the Stock, Bonds, Bills and Inflation, 2009 Yearbook. Over the period 1926 through 2008, Ibbotson estimated that the arithmetic average of the achieved total return on the S&P 500 was 11.7%, and the total return on long-term Treasury bonds was 6.1%. The indicated equity risk premium is 5.6% (11.7% - 6.1% = 5.6%).[10]

As I discussed in my direct testimony, the more accurate way to estimate the market risk premium from historic data is to use the *income* return, not *total* returns, on government bonds. The long-term (1926-2008) market risk premium (based on income returns, as required) is 6.5%, rather than 5.6%. Ibbotson Associates recommends use of the *income* return on government bonds as a more reliable estimate of the historical market risk premium because the income component of total bond return (i.e., the coupon rate) is a better estimate of expected return than the total return (i.e., the coupon rate + capital gain).[11] In other words, bond investors focus on income rather than realized capital gains/losses. This correction alone increases Mr. Parcell's

[10] Parcell Direct Testimony, page 34, line 7.

[11] *See* Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation 2007 Yearbook: Valuation Edition*, 66 (2007).

CAPM estimate by approximately 70 basis points (the difference between 6.5% and 5.6% times Mr. Parcell's beta of 0.78 shown on Schedule 13).

Q. Do you agree with Mr. Parcell's third estimate of 3.9% for the MRP in his CAPM analysis?

A. No, I do not. For his third MRP proxy, Mr. Parcell uses a historical risk premium of 3.9% based on the aforementioned Ibbotson historical MRP study, only this time relying on the geometric average of historical returns instead of the arithmetic average of historical returns.

Q. Is it appropriate to use geometric averages in measuring expected return?

A. No, it is not. Arithmetic means are appropriate for forecasting and estimating the cost of capital, while geometric means are not.[12] Indeed, the Ibbotson Associates publication cited on page 41 of Mr. Parcell's testimony contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. There is no theoretical or empirical justification for the use of geometric mean rates of return. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate.

[12] See Roger A. Morin, *The New Regulatory Finance*, chapter 11 (2006); Brealey, Myers, and Allen, *Principles of Corporate Finance* (8th ed. 2006).

It is inappropriate to average the arithmetic and geometric average return; they measure different quantities in different ways. Please see Morin, R. A., *The New Regulatory Finance*, chapter 11 (2006) for a discussion regarding the theoretical underpinnings, empirical validation, and the consensus of academics on why geometric means are inappropriate for forecasting and estimating the cost of capital.

Q. What is the effect of Mr. Parcell's use of the geometric mean instead of the arithmetic mean MRP?

A. Mr. Parcell's use of the geometric mean MRP of 3.9% rather than the arithmetic mean of 5.6% significantly understates the MRP, which suggests an understatement of HECO's cost of equity by 120 basis points (1.2%) using Mr. Parcell's beta for HECO of approximately 0.73:

$$\beta_{HECO} \times (\text{Arithmetic Mean} - \text{Geometric Mean})$$

$$0.73 \times (5.6\% - 3.9\%) = 0.73 \times (1.7\%) = 1.2\%$$

Q. Should the historical MRP be estimated using the income component of bond returns or the total return component?

A. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. As discussed earlier, the use of the latter is a more reliable estimate of the historical MRP because the income component of total bond return (i.e., the coupon rate) is a far better estimate of expected return than the total return (i.e., the coupon rate plus capital gains), because realized capital gains/losses are largely unanticipated by investors.

Q. Mr. Parcell claims on page 60 of his testimony that the empirical CAPM inflates the CAPM result for the selected company or industry. Is he correct?

A. I do not believe it does. For companies with betas less than one, the CAPM understates the return; for companies with betas greater than one, the CAPM overstates the return. I discussed the conceptual and empirical foundations in Appendix A of my direct testimony.

Q. Mr. Parcell disagrees with the risk premium methodology because economic conditions today are different and risk premiums are unstable from year to year. How do you respond?

A. On pages 61-62 of his testimony, Mr. Parcell critiques the risk premium method on two grounds: 1) the method assumes that past is prologue, and 2) the method assumes that the risk premium is constant over time whereas in fact the risk premium results are dominated by the influence of capital gains in many years.

The first criticism is unwarranted. I employed returns realized over long time periods rather than returns realized over more recent time periods. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. A risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never commit any funds.

I have ignored realized risk premiums measured over short time periods because they are heavily dependent on short-term market movements. Instead, I have relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. By using the entire study period to estimate the appropriate market risk premium, subjective judgment is minimized and many diverse regimes of inflation, interest rate cycles, and economic cycles spanned.

Mr. Parcell's second concern is unwarranted as well. The influence of unexpected capital gains is offset by the influence of unexpected capital losses. To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Thus the best estimate of the future risk premium is the historical mean. As I explained in my direct testimony, because I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the successive market risk premiums from year to year, it is reasonable to assume that these quantities will remain stable in the future.

Q. What do you conclude from Mr. Parcell's rate of return recommendation?

A. Mr. Parcell's recommended ROE is understated. Using current stock prices that reflect the impact of the ongoing financial crisis on capital costs and its devastating impact on utility stock prices raises Mr. Parcell's DCF estimate by

45 basis points from this factor alone. Recognition of the proper functional form of the DCF model (20 basis points), a far greater emphasis on analysts' growth forecasts in the DCF analysis (120 basis points), and the appropriate historical MRP in the CAPM analysis (50 - 120 basis points), would suggest much higher returns that are quite close to my own ROE recommendation for HECO.

REVENUE DECOUPLING RISK ADJUSTMENT

Q. Dr. Morin, do you agree with Mr. Parcell's downward risk adjustment on account of the RDM?

A. I disagree with the magnitude of the adjustment. Mr. Parcell argues that a steep downward ROE adjustment of 50 basis points is required to account for what he considers to be the risk-reducing effect of the RDM relative to the comparable companies is warranted. While I agree with the notion of a downward risk adjustment, I disagree with its magnitude.

Not only is this 50 basis points adjustment arbitrary, but most, if not all, energy utilities in the industry are under some form of adjustment clause/cost recovery/rider mechanism(s). The approval of adjustment clauses, riders, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond rating and business risk scores. The experience with the operation of RDMs for electric utilities in general is very scant at this time, let alone the specific RDM variant that the Commission may adopt.

Moreover, a RDM can actually increase regulatory risks, particularly the risk of the Commission denying timely recovery if deferred balances get too large. Therefore, it is speculative as to whether, and if so how, a RDM will affect the Company's risk profile. My own judgment is that a maximum of 25 basis points adjustment is warranted at best.

UPDATED RECOMMENDATION

Q. What is the purpose of this section of your rebuttal testimony?

A. The purpose of this section is to review my original ROE recommendation in light of the changes in capital markets and in the Company's risk profile that have occurred since I prepared my direct testimony. My original ROE recommendation of 11.25% is amended to a range of 11.00% - 11.25% assuming that the Company's proposed RDM is approved, and a range of 11.25% - 11.50% otherwise.

Q. Please describe the current state of the capital markets compared to when you prepared your testimony in May 2008.

A. As discussed earlier, capital markets continue to be in a state of turmoil, although some modest signs of improvement have appeared. The debt markets have witnessed record high yield spreads and a more severe differentiation between the spreads charged to companies with different levels of credit. A fundamental structural upward shift in risk aversion has occurred as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all market participants.

Q. Can you briefly describe the behavior of interest rates since you filed your original testimony based on May 2008 data?

A. Yes. Significant changes have occurred in capital market conditions since I prepared my original testimony for HECO based on May 2008 data. The current level of U.S. Treasury 30-year long-term bond yield is 4.0%, versus 4.6% when I prepared my direct testimony. The decrease in interest rates lowers the CAPM and Risk Premium estimates that are based on the risk-free rate.

Q. Dr. Morin, what has happened to electric utility betas since you prepared your direct testimony?

A. Betas have decreased from the 0.85 level to the 0.75 level although I note that betas are estimated on five-year historical periods, and therefore do not capture the current increased risk environment faced by utilities.

Q. How much weight should be accorded to the CAPM results under current market circumstances?

A. I believe much less weight should be accorded to the CAPM results under present economic circumstances for reasons discussed earlier in my rebuttal.

Q. Dr. Morin, please describe what has happened to the DCF results since the financial crisis began.

A. The Dow Jones Utility Average has fallen some 35% over the past year. The devastating downward impact of the financial crisis on utility stock prices has resulted in lower stock prices, implying higher dividend yields which in turn imply higher DCF estimates. As of May 2009, the DCF results for the energy utilities have increased significantly by 100 basis points in response to lower stock prices (higher dividend yields) following the financial crisis.

Q. What input data did you use in the CAPM analysis to arrive at your updated ROE?

A. For the risk-free rate, I used 4.0% based on the current level of long-term Treasury interest rates. For beta, I used 0.75 and for the market risk premium ("MRP"), I used 6.5%.

Q. Did you make any methodological changes in your historical risk premium analysis of the utility industry?

A. In light of the financial crisis that began after I prepared my direct testimony, I made two changes in my historical risk premium analysis. First, in my original testimony, I relied on the Moody's Electric Utility Index to perform my historical risk premium study. Following the acquisition of Moody's by Mergent in 2002, publication of the electric utility index was discontinued. Therefore, I chose to rely on the S&P Utility Index instead of the Moody's Index in order to ensure continuity and timeliness of the risk premium data. I note that this change does not alter the results significantly.

Second, given the current chaotic state of the capital markets at this time, it is no longer appropriate to perform a historical risk premium analysis using government bond yields. Trends in utility cost of capital are directly reflected in their cost of debt and are not directly captured by a risk premium estimate tied to government bond yields. This is especially germane in the current financial crisis where corporate spreads have reached record levels.

Because a utility's cost of capital is determined by its business and financial risks, it is reasonable to surmise that its cost of equity will track its cost of debt more closely than it will track the government bond yield. To guard against this possibility, I have performed my historical premium analysis of the utility industry using the A-rated utility bond yield instead of the government bond yield. The average historical risk premium over the period is 5.0% over both utility bond returns and utility bond yields. Given that the current yield on utility bonds rated single A is 6.2%, and using the historical risk premium estimate of 5.0%, the implied cost of equity from this particular method is 6.2% + 5.0% = 11.2% without flotation costs and 11.5% with the flotation cost allowance.

I did not implement the allowed risk premium analysis in view of the scarcity of decisions since the financial crisis began in Fall 2008.

Q. Did you make any methodological changes in your DCF analyses?

A. Not really. I relied on current stock prices and growth forecasts from both Value Line and financial analysts. The only minor departure from my original DCF analysis is that for my second group of comparable utilities, I relied on the electric utilities that make up the S&P Utility index instead of the Moody's Utility Index. The use of S&P Utility Index instead of the Moody's Index is necessitated by the discontinued publication of the Moody's Index since the acquisition of Moody's by Mergent, and is also consistent with the use of that same index in my historical risk premium analysis.

Q. *Dr. Morin, please summarize your updated results from the various methodologies.*

A. The revised ROE estimates for the average risk electric utility are summarized in the table below.

STUDY	Updated ROE
CAPM	9.2%
Empirical CAPM	9.6%
Risk Premium Electric	11.5%
DCF Vert. Integrated Electric Utilities Value Line Growth	12.3%
DCF Vert. Integrated Electric Utilities Zacks Growth	12.6%
DCF Moody's Elec Utilities Value Line Growth	12.0%
Moody's Elec Utilities Zacks Growth	12.0%

The average result from all the methodologies is 11.3%, rounded to 11.25% to the nearest quartile.

Q. *Have you adjusted the cost of equity estimates to account for the fact that HECO's risk is higher than the industry average, as you did in your direct testimony?*

A. No, I did not. In my original testimony, I applied a 25 basis points risk premium in order to allow for HECO's greater investment risk relative to the industry, mainly due to its relatively small size. At the time I prepared my direct testimony, HECO's investment risks certainly exceeded those of the industry. I estimated the risk adjustment to be at least 25 basis points. Should the Commission allow the Company to establish and implement a revenue adjustment mechanism as proposed in the joint decoupling proposal filed by the Company and the Division of Consumer Advocacy in the decoupling proceeding (Docket No. 2008-0274), and given the various riders discussed earlier, the need for such a risk premium is unnecessary, and HECO's risk is comparable to the industry average.

Q. What is your final conclusion regarding HECO's updated cost of common equity capital?

A. Based on the results of all my analyses, the application of my professional judgment, the risk circumstances of HECO, and the unsettled current market environment, it is my opinion that a conservative just and reasonable return on the common equity capital of HECO's electric utility business is in a range of 11.00% - 11.25% assuming approval of decoupling in its existing format and in a range of 11.25% - 11.50% without.

Q. Does this conclude your rebuttal?

A. Yes, it does.

HECO RT-20
DOCKET NO. 2008-0083

REBUTTAL TESTIMONY OF
TAYNE S. Y. SEKIMURA

SENIOR VICE PRESIDENT, FINANCE AND ADMINISTRATION

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Rate Base

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura. I am the Senior Vice President, Finance and Administration of Hawaiian Electric Company, Inc. ("HECO" or the "Company")

Q. Have you previously testified in this proceeding on the return on rate base?

A. Yes, I have presented direct testimony as HECO T-20 and supporting exhibits and workpapers.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to:

1) Present the Company's updated composite cost of capital;
2) Discuss the settlement agreement among the parties as to the capital structure for HECO, as well as the positions of the Department of Defense and Division of Consumer Advocacy with regard to the cost of various components of the Company's capital structure (in particular, return on equity "ROE");
3) Identify key provisions of the October 20, 2008 *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* ("Energy Agreement") impacting HECO's financial integrity; and
4) Discuss changes in the economic environment since the filing of my direct testimony.

UPDATED COMPOSITE COST OF CAPITAL

Q. What is HECO's updated composite cost of capital for the test year 2009?

A. HECO's updated composite cost of capital is 8.73% (with decoupling mechanism as proposed by the Company and the Consumer Advocate) as shown on HECO-R-2001.

Q. What updates have you made to the cost of capital calculation?

A. The cost of capital filed in direct testimony was revised to reflect the following changes:

1) Updated the capitalization balances to reflect December 31, 2008 recorded. This changed the long-term debt, preferred stock, and common equity balances.

2) The short-term debt amount is zero, based on the terms of the Settlement Agreement.

3) The incremental long term borrowings increased from $60 million to $90 million (test year average incremental balance increased $15 million, from $30 million to $45 million). The interest rate for incremental long term financing increased from 6.5% to 7%.

4) The incremental preferred stock of $80 million ($40 million test year average) at 8.5% was eliminated. HECO is planning to issue common stock instead which I discuss further later in my testimony.

5) Common equity was adjusted for the December 31, 2008 recorded balance. The 2009 activity was updated to reflect the planned equity infusion of $100 million (subject to PUC approval) and 2009 forecasted changes based on an updated Sources and

Applications of Funds, including a reduction in common equity of $28.94 million to infuse capital in HECO's subsidiaries.

These changes are shown in HECO-R-2002, HECO-R-2003, HECO-R-2004, HECO-R-2005 and the related workpapers.

Short-Term Debt

Q. What is the revised average short-term debt balance for test year 2009?

A. The average short-term "debt" balance is $0.

Q. Why did the short-term debt balance change?

A. The average short-term debt balance changed as a result of the December 31, 2008 balance being a short-term investment rather than the short-term debt balance previously forecasted. The forecast Sources and Applications of Funds for 2009, as shown on HECO-R-2006 indicates a net change of $27 million in additional short-term investment. Use of the actual beginning balance being in investment mode and the forecast net change in 2009 would have resulted in the Company projecting a short-term investment in its capital structure. For purposes of settlement, the parties agreed that the average short-term debt amount would be assumed to be zero for the test year.

Long-Term Debt

Q. What is the revised average long-term debt balance for test year 2009?

A. The average long-term debt balance is $577 million as shown on HECO-R-2003.

Q. Why did the long-term debt balance change?

A. The average long-term debt balance changed because the forecast incremental long-term debt issuance of $60 million has increased to $90 million. The Companies applied for approval of issuance of revenue bonds in Docket

No. 2008-0281 (filed October 29, 2008). The larger expected issuance was based on the fact that HECO has sufficient project costs that qualify for revenue bond financing and larger issuances are more economical than separate smaller issuances. Because bond issuances have certain fixed costs which are not proportionate to the size of the issuance, a larger issuance spreads the fixed costs over more debt and lowers the effective debt cost.

Q. What is the revised estimated cost of incremental long-term debt?

A. The forecast estimated interest rate for incremental long-term debt increased from 6.5% to 7%, based on quotes received in April 2009 from bankers. As a result, the weighted average interest rate for long-term debt is 5.81% rather than the 5.75% filed in direct testimony.

Preferred Stock

Q. What is the revised average preferred stock balance for test year 2009?

A. The revised average preferred stock balance for test year 2009 is $21 million as shown on HECO-R-2004.

Q. Why did the preferred stock balance change from direct testimony?

A. Because the Company has abandoned plans for a preferred stock issuance in 2009, the incremental preferred stock issuance has been removed from the test year balance.

Q. In the Energy Agreement, the parties agreed to support a reasonable preferred stock or hybrids securities offering by the Company on the basis that it represents a less expensive form of financing than equity, but does not negatively impact the utility's debt ratio as much as debt would. Why did the Company abandon its plans for a preferred stock issuance in 2009?

A. The Company plans to issue common stock in lieu of preferred stock because the economic conditions are more supportive of a common stock issuance than of a preferred stock issuance. There is currently no market for preferred stock.

Q. What is the revised estimated cost of preferred stock for test year 2009?

A. The revised estimated cost of preferred stock for test year 2009 is 5.48% rather than the 7.62% filed in direct testimony. This is because the previously forecast incremental preferred stock issuance of $80 million at 8.5% was eliminated from the test year capitalization.

<u>Common Equity</u>

Q. What is the revised average common equity balance for test year 2009?

A. The revised average common equity balance for test year 2009 is $790 million as shown on HECO-R-2005.

Q. Why did the common equity balance change from direct testimony?

A. Common equity was adjusted for the December 31, 2008 recorded balance. In addition, the 2009 activity was updated to reflect the planned equity infusion of $100 million and 2009 forecasted changes based on an updated Source and Application of Funds (as shown on HECO-R-2006), including a reduction in common equity of $28.94 million to infuse capital in HECO's subsidiaries. The Companies applied for approval of an issuance of common stock in Docket No. 2009-0089 (filed April 20, 2009).

Q. Why does the Company plan to issue common stock?

A. The Company is planning on an infusion of common equity to improve the Company's credit quality. The equity infusion decreases financial risks by improving the debt/total capitalization ratio, relative to what it would have been without the infusion of equity. In direct testimony with a preferred stock issuance instead of an equity infusion, the Company projected a 56% debt/total capitalization ratio (including imputed debt). The Company currently projects a debt/total capitalization ratio (including imputed debt) of 56% with the equity infusion (as shown on HECO-RWP-2007); however, without the $100 million equity infusion, the Company would have to increase its debt, all other things being equal, the debt/total capitalization ratio (including imputed debt) would have been 59%, which would negatively impact HECO's credit quality.

Q. What is the Company's estimate of a fair and reasonable return on common equity for HECO?

A. The Company accepts Dr. Morin's recommendation of 11.0% return on equity with the Revenue Balancing Account and the Revenue Adjustment Mechanism.

<u>Revised Capital Structure</u>

Q. What is the revised capital structure?

A. As a result of the changes described, a test year capital structure consisting of 0% short-term investments, 40.76% long-term debt, 1.96% hybrid securities, 1.46% preferred stock, and 55.81% common equity is appropriate.

<u>Updated Financial Ratios</u>

Q. Have you updated the projected financial ratios for the test year as presented in your direct testimony?

A. Yes. We have updated the financial ratio calculations in HECO-R-2007. There are two sets of ratios:

1. HECO receiving rate relief and earning 11.0% return on common equity, and
2. No rate relief.

Q. What are the implications of the updated ratios based on an 11.0 % return on common equity?

A. There were no significant changes to the financial ratios presented in direct testimony as a result of the revisions made to the various components of the cost of capital. Based on a current Standard and Poor's ("S&P") business profile of "strong", the ratios are analyzed as follows:

Without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.1 in BBB range of 3.0-3.5)
- the funds operations/total debt ratio is indicative of a BB+ rating (12% in BB+ range of 10-16.67%)
- the total debt/total capital ratio is indicative of a BB+ rating (56% in BB+ range of 55-60%).

With rate relief and 25% risk factor for purchased power:

- the funds from operations/interest coverage ratio is indicative of a A+ rating (4.6 in A+ range exceeding 4.5)
- the funds from operations/total debt ratio is indicative of an BBB- rating (21% in BBB- range of 16.67-23.33%)
- the total debt/total capital ratio is indicative of a BBB rating (50% in BBB range of 45-50%).

In our discussions, S&P continues to indicate that HECO's financial ratios are weak for the Company's BBB credit rating. In its November 26, 2008 Summary, S&P stated:

> The stable outlook reflects our expectation that, for now, HECO appears to have reasonable but not certain prospects for maintaining its existing financial profile, which is weak for the rating. Multiple near-term challenges face the company and

> include the uncertainties of the cost and feasibility impacts of the CEI, the potential for a significant reduction in electric sales in 2009 (due to economic contraction, energy efficiency initiatives, and customer response to high prices), and a recent softening in leading economic indicators. These challenges suggest that a negative outlook or downward revision to the ratings could be possible over the outlook horizon, as further weakening in the financial profile will not support ratings, and near-term business risk will be elevated until the particulars of the CEI are in place and prove to be supportive. Consistent, timely rate relief will continue to be key, and could offset or mitigate the effects of a declining economic environment, but decoupling or other measures are not expected to be available to the company before late 2009 or early 2010. Given these challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

In discussions in May 2009, S&P reiterated that our financial credit metrics would not support our current BBB rating and S&P would need to get more comfortable with our financial metrics. My interpretation of S&P's comment is that HECO's financial credit metrics without improvement from rate relief, the Revenue Balancing Account, the Revenue Adjustment Mechanism, and the purchased power adjustment clause would not support HECO's current BBB rating.

Q. What is your conclusion based on these ratios?

A. My conclusion is that rates established based on the Company's proposed cost of capital of 8.73% would be sufficient to maintain the Company's current credit rating, if supported by the Revenue Balancing Account, Revenue Adjustment Mechanism, and purchased power adjustment clause.

SETTLEMENT AGREEMENT AND CONSUMER ADVOCATE AND DEPARTMENT OF DEFENSE POSITIONS

Q. Are the parties in agreement on the capital structure for ratemaking purposes?

A. Yes. The Consumer Advocate, the Department of Defense and the Company have agreed to use a capital structure of 0% short-term debt, 40.76% long-term debt, 1.96% hybrid securities, 1.46% preferred stock, and 55.81% common equity. HECO initially reflected a balance in the short-term investment based on the recorded December 31, 2008 short-term investment balance and the forecast additional net short-term investment in 2009. However, HECO agreed to accept the Consumer Advocate's position of $0 short-term debt.

Q. Are the parties in agreement on the cost of various components of the capital structure other than the cost of common equity?

A. Yes. The parties agreed on the cost of long-term debt of 5.81%, cost of hybrid securities of 7.41%, and cost of preferred stock of 5.48%.

Q. Have the parties reached agreement regarding the cost of common equity?

A. No. In the settlement agreement, the parties agreed to a cost of common equity of 10.5% as presented on HECO-R-2001 for interim rate increase purposes only. In direct testimony, the Company requested a cost of common equity of 11.25% as presented by Dr. Morin in HECO T-19. Dr. Morin maintains his cost of equity in his rebuttal testimony in HECO RT-19 in the range of 11.0% to 11.25% with the currently proposed decoupling mechanism. The Company is willing to accept a rate of return on common equity at the low end of the range provided by Dr. Morin, 11.0%, with the proposed decoupling mechanism. The Consumer Advocate's witness, Mr. Parcell, recommends a cost of equity rate of 9.5% to 10.5%. The Department of Defense's witness, Mr. Hill, estimated the equity capital cost of similar-risk electric utility companies to fall in a range of 9.25% to 10.25%, with a specific return on common equity for HECO of 9.5%.

ENERGY AGREEMENT

Q. The cost of capital witnesses for the other Parties have taken the position that incentive mechanisms in the Energy Agreement – decoupling, the power purchase adjustment clause and the clean energy infrastructure surcharge - lower the Company's operating risk and thus, its required rate of return on common equity. What is HECO's position?

A. As Dr. Morin states in HECO RT-19, while adjustment clauses and cost tracking mechanisms are beneficial in mitigating operating risk, the approval of adjustment clauses and cost recovery mechanisms by regulatory commissions is widespread in the utility business and, in HECO's case, there are other significant factors to consider that work in the reverse direction for HECO.

The far-reaching nature of the Energy Agreement, and the much higher renewable portfolio standards enacted by the legislature this month as contemplated by the Energy Agreement, present new and increased risks to the Company, such as (1) the dependence on third-party suppliers of renewable purchased energy, which could impact the utilities' achievement of their commitments under the Energy Agreement and/or the utilities' ability to deliver reliable service; (2) the impact of intermittent power to the electrical grid and reliability of service if appropriate supporting infrastructure is not installed or does not operate effectively; (3) the likelihood that the utilities may need to make substantial investments in related infrastructure, which could result in increased borrowings and, therefore, materially impact the financial condition and liquidity of the utilities; and (4) the commitment to support a variety of initiatives, which, if approved by the Commission, may have a material impact on the results of operations and financial condition of the utilities depending on their design and implementation.

Any risk assessment must also take into consideration the impact of the massive additional renewable energy resources being taken on by the Company in additional power purchase agreements ("PPAs") on HECO's balance sheet. S&P already adds about $568 million in imputed debt from HECO's current PPAs to assess HECO's credit risk. The additional PPAs resulting from the Energy Agreement will undoubtedly make this imputed debt calculation much higher, and HECO must balance the capital structure accordingly.

In addition, the implementation of new cost recovery mechanisms incorporated in the Energy Agreement (including the Renewable Energy Infrastructure Program/Clean Energy Infrastructure ("REIP/CEI") Surcharge, the purchased power clause and the revenue adjustment mechanism, which are discussed below) is intended, in part, to help HECO maintain its existing credit rating and investment risk profile, by helping the utilities to recover in a more timely fashion the costs of the infrastructure and other investments required to support significantly increased levels of renewable energy, and helping the Company achieve a fair rate of return.

Further, none of the cost recovery mechanisms will eliminate the need for the Company to raise the additional capital required to fund the infrastructure projects. For example, the REIP/CEI Surcharge would provide

HECO with a more timely recovery method for Commission-approved infrastructure projects after such approved projects are placed in service, but generally would not be a means of raising capital prior to the approved projects' installation and use.

Q. Does the Energy Agreement affect HECO's financial integrity?

A. Yes it does. In considering the Energy Agreement's impact on HECO's financial integrity, the whole financial picture needs to be considered. The Energy Agreement (also referred to as "Hawaii Clean Energy Initiative" or "HCEI") committed HECO to facilitate the integration of substantial amounts of clean, renewable energy into its grid and to enable electricity consumers to manage their electricity use more effectively. In this regard, S&P observed in its November 26, 2008 Summary regarding HECO that: "The level of renewable, energy-efficiency, and distributed-generation investment is significant. Just focusing on HECO (e.g., excluding goals for MECO and HELCO) the HCEI would require 148 MW of renewable installed by 2010, jumping to 890 MW by 2015. Similarly, for energy efficiency and distributed generation goals, 169 MW of measures would need to be in place by 2010, rising to 1,015 MW by 2015." Uncertainty relating to the requirements for and technology of capital expenditures relating to the Energy Agreement increases business risk, in addition to the financing and cost recovery risks which increase financial risk.

Q. What are some of the key provisions of the Energy Agreement which impact financial integrity?

A. The Energy Agreement provides that the Energy Agreement Parties will pursue a wide range of actions with the purpose of decreasing the State of

Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation. The Energy Agreement documents a course of action to make Hawaii energy independent, while recognizing the need to maintain HECO's financial health in order to achieve that objective. Thus, as noted in S&P's November 26, 2008 Summary[1], the next few years are likely to be pivotal for Company credit quality, as the HCEI program details will likely shape the Company's financial position for years to come. Key Energy Agreement provisions which impact financial integrity include the following:

1) 40% Renewable Portfolio Standard ("RPS")
2) Feed-In Tariffs
3) Decoupling
4) Purchased Power Adjustment Clause
5) REIP/CEI Surcharge

<u>40% Renewable Portfolio Standard</u>

Q. How have HECO's commitments to renewable energy increased?

A. The HCEI Agreement commits HECO to facilitate the integration of substantial amounts of clean, renewable energy (wind energy in particular) into its grid and to enable electricity consumers to manage their electricity use more effectively. The agreement explicitly provides for the Energy Agreement Parties to seek amendment to the Hawaii RPS law. To that end, the Hawaii State Legislature passed H.B. No. 1464 H.D. 3 S.D. 2 C.D. 1 during its 2009 legislative session. Among other things, this legislation would increase

[1] Filed in Rate Case Update HECO T-20 on December 23, 2008.

electric utilities' 2020 RPS requirement from 20% to 25%, and add a new 40% requirement for the year 2030. Prior to January 1, 2015, at least 50% of a utility's RPS would need to be met by "electrical generation using renewable energy as the source". After January 1, 2015, however, a utility's entire RPS would need to be met by renewable generation, and "electrical energy savings" will no longer count toward RPS requirements.

In addition, the legislation directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy-efficiency programs and technologies." In particular, the legislation would require that the energy efficiency portfolio standards ("EEPS") be designed to achieve 4,300 GWh of electricity use reductions statewide by 2030, with interim Commission-established goals for 2015, 2020, and 2025. The Commission may also adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies. Similar to the RPS law, "The Commission may establish incentives and penalties" with respect to the EEPS, and the Commission is required to evaluate the EEPS every five years, beginning in 2013. In addition, beginning in 2015, "electric energy savings brought about by the use of renewable displacement or off-set technologies, including solar water heating and seawater air conditioning district cooling systems" will count toward the EEPS.

Although as discussed above, the revised RPS law would require that after 2014 the RPS goal be met solely with renewable energy generation versus including energy savings from energy efficiency measures, energy savings from energy efficiency measures would be counted toward the achievement of the overall Energy Agreement 70% goal. Nevertheless, as stated in my response to DOD-IR-44, there is inherent uncertainty in forecasting the future impacts of DSM programs that cannot be overcome by hypothetically "accurate" estimates.

Q. How does the 40% RPS impact the Company's financial integrity?

A. The increase in RPS significantly increases the Company's business risk. Many of the undertakings which are necessary to meet the new RPS have never been attempted, in this jurisdiction, and perhaps anywhere. They include the integration of 400 MW of wind transmitted from Lanai and Molokai to Oahu via undersea cable, integration of numerous renewable sources through purchased power agreements (many of which will be intermittent sources), conversion of the existing fossil-fueled units to biofuel, and conversion of the existing meter system to an advanced metering infrastructure ("AMI") system to enable time of use pricing. In this regard, S&P summarized its concerns in its November 28, 2008 Summary as follows: "Credit concerns around the CEI focus on three areas: the feasibility of the plan and what the ramifications are for HECO if it cannot meet the ambitious program outlined in the CEI, the costs of CEI and whether ratepayers will ultimately be willing to bear them, and the potential impact on reliability."

Q. Have the credit reporting agencies taken note of the integration of 400 MW of wind into HECO's system?

A. Yes. In its November 26, 2008 Summary, S&P stated that, "The details on any such arrangement would be important to credit quality, as HECO's balance sheet may not be able to withstand a large infrastructure investment of this type." In addition to new clean energy-related efforts, the Company also needs to expend additional dollars to operate and maintain its aging infrastructure in order to sustain reliable service and to keep up with escalating costs for labor, materials and services.

Feed-In Tariffs

Q. What is the feed-in tariff?

A. Under the feed-in tariff, the utility would be required to purchase certain types of energy under certain conditions at a rate established by the Commission.

Q. How will the feed-in tariff impact the Company's financial integrity?

A. The feed-in tariff imposes an obligation to purchase certain types of power under certain conditions. The impact on the Company's financial integrity depends on many factors including the magnitude of the obligation, the impact on the operations of the Company, and the conditions under which the Company must make payments. Large obligations will result in larger amounts of imputed debt, which will negatively impact the Company's financial ratios as viewed by credit rating agencies and negatively impact credit quality. An adverse impact on the Company's operations may reduce reliability and negatively impact business risk which would adversely impact credit quality. A tariff which requires the Company to make payments regardless of whether the energy is delivered would be detrimental to the financial integrity of the Company because it could result in capital lease obligations being recorded on the Company's financial statements. Capital lease obligations result in additional debt, and thereby negatively impact the Company's financial ratios and credit quality.

Decoupling

Q. Please summarize the major provisions of the Decoupling mechanism being addressed in Docket No. 2008-0274.

A. The major provisions of the Decoupling mechanism are:

1) Revenue Balancing Account ("RBA") which removes the link between sales and revenues,
2) Revenue Adjustment Mechanism ("RAM") which adjusts revenues based on indexed cost changes and certain rate base additions, and
3) Earnings Sharing Mechanism which provides for sharing of earnings in excess of the rate of return deemed reasonable in the latest rate case.

Q. How will the RBA impact the Company's financial integrity?

A. Approval of the RBA in the interim order in this docket is critical to the financial integrity of this Company because it addresses the current deterioration in sales resulting from the poor economy and energy efficiency programs. The RBA is credit enhancing because it reduces earnings volatility, ultimately lowering the Company's business risk, all else being equal. The RBA cuts both ways, however, and would reduce earnings potential if sales were to increase. Credit rating agencies view this mechanism as critical to maintaining HECO's credit quality.

Q. How will the RAM impact the Company's financial integrity?

A. The RAM is critical to maintaining the Company's financial integrity in light of the numerous commitments under the Energy Agreement. It will allow the Company to demonstrate to investors that the Company has the revenues and liquidity to support the numerous expenditures and purchased power commitments under the Energy Agreement.

Q. Assuming that a decoupling mechanism is approved, should the Company's required ROE decrease?

A. Not necessarily. As discussed above, HECO's entire financial picture needs to be taken into account when evaluating the Company's risk. Many of HECO's comparable utilities already have decoupling mechanisms in place. Mr. Fetter discusses this in his testimony. Please see T-19, p. 9. As a result, although an increase in HECO's ROE would likely be warranted in the event the Company's decoupling proposal were rejected, this does not imply a similar downward adjustment due to the approval of such a mechanism.

As explained in a June 30, 2008 report to the Minnesota Public Utilities Commission titled, "Revenue Decoupling Standards and Criteria," improvements in utility bond ratings due to decoupling generally require several years to play out and the consequent benefits for customers are therefore slow to materialize. The impact of the decoupling mechanism on financial integrity and rate of return on equity are discussed by Mr. Fetter in RT-21 and Dr. Morin in RT-19.

<u>Purchased Power Adjustment Clause</u>

Q. Do PPAs affect the Company's credit quality?

A. Yes. As I discussed in direct testimony, rating agencies are aware of the Company's large purchased power obligations. S&P states in its November 28, 2008 Summary report:

> The consolidated financial profile is 'aggressive', reflecting in part the very heavy debt imputation Standard & Poor's Ratings Services applies to HECO for its long-term power purchase agreements (PPAs). These obligations added about $469 million in on-balance-sheet debt 2007 and about $568 million beginning in March 2008 and reflect evergreening of PPA obligations. (Consistent with our published criteria, we assume that expiring

> PPA contracts are replaced with new ones at similar terms.) While we apply significant debt obligations to HECO, we also recognize the historical reasons that have led to HECO buying a substantial amount of its power supply from third-party suppliers and that the regulatory recovery of capacity costs associated with these contracts has been supportive.

Q. Please explain the Purchased Power Adjustment Clause agreed to by the parties in the Energy Agreement and proposed by HECO in this docket.

A. The parties to the Energy Agreement agreed to a separate clause which would allow the Company to pass through all reasonably incurred purchased power agreement costs including all capacity, O&M, and other non-energy payments approved by the Commission (including those acquired under the feed-in tariff). The Company proposes to move these costs from base rates to a separate clause which will be adjusted monthly and reconciled quarterly.

Q. Why is this clause of particular importance in the current environment?

A. HECO intends to aggressively pursue renewable energy through purchased power agreements. As noted in my response to DOD-IR-47, in addition to the proposed projects grandfathered from competitive bidding, HECO's renewable energy request for proposals ("RFP") and future RFPs could result in additional power purchase contracts.

Further, the State recently enacted legislation which eliminated the requirement that the rate for purchase of electricity by a utility shall not be more than the cost avoided by the utility.[2] HECO expects to enter into more purchased power contracts in the near future. In order to facilitate more purchased power contracts, HECO needs assurance that the purchased power expenses will be fully recovered from customers. Full cost recovery is fair because HECO does not earn a profit on purchased power expenses.

[2] See Act 50 H.B. No. 1270 H.D. 1 S.D. 2 (2009)

Q. How would this clause affect the Company's credit quality?

A. As I discussed in my direct testimony, a purchased power adjustment clause which provides great assurance of cost recovery of all purchased power costs will enhance the Company's financial profile which would result in financial ratios more supportive of the Company's current credit rating. S&P did confirm in conversation, that the Purchased Power Adjustment Clause, as proposed, would result in the lowering of the risk factor S&P applies in calculating imputed debt. S&P has indicated that the risk factor would be lowered from 50% to 25%, which would cut the imputed debt in half. S&P further indicated, however, that this change would not result in any ratings upgrade, rather it would be more supportive of HECO's current credit rating.

Q. How does the Company's credit quality impact purchased power development?

A. When the Company has strong credit, it is more likely to attract developers (because those developers have a stronger ability to finance their projects) than when the Company's credit is weak. S&P generally will not rate a project higher than the lowest rated entity (e.g., the offtaker) that is crucial to project performance, unless that entity may be easily replaced, notwithstanding its insolvency or failure to perform. By maintaining its current credit rating, the Company would be near the lowest credit rating necessary to be deemed a credit worthy offtaker by financial institutions financing independent purchased power developments.

Q. How would recovery of all purchased power costs through a purchase power cost recovery mechanism impact customers?

A. As I discussed in direct testimony, purchased power energy costs currently are recovered through ECAC, which would not change. Purchased power capacity and operations & maintenance costs are generally stable costs, and therefore we would not expect any significant or immediate rate impact. In the long-term however, customers could potentially benefit through: 1) decreased borrowing rates (and investors' rate of return requirements), or 2) increased debt proportions in the Company's capital structure, or 3) some combination of the two.

REIP/CEI Surcharge

Q. What is the REIP/CEI Surcharge?

A. The parties to the Energy Agreement agreed to the establishment of an REIP/CEI Surcharge to expedite cost recovery of infrastructure that supports greater use of renewable energy or utility grid efficiency.[3] The proposed REIP/CEI Surcharge also would be used to recover costs that would normally be expensed in the year incurred and to recover costs stranded by clean energy initiatives, subject to the Commission's prior approval.

Q. What projects does the Company propose to recover costs through the REIP/CEI Surcharge?

A. The Company has applied for recovery of AMI costs through the REIP/CEI Surcharge. The Company also anticipates it will soon be filing an application to recover costs incurred and to be incurred for the studies of land-based infrastructure to be built on Oahu to support the integration of wind farms on Lanai and Molokai ("Big Wind Studies").

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[3] Section 29 of the Energy Agreement called for a Clean Energy Infrastructure ("CEI") Surcharge. The CEI Surcharge is equivalent to the REIP Surcharge that the HECO Companies proposed in Docket No. 2007-0416. On November 28, 2009, the HECO Companies and the Consumer Advocate filed a letter agreeing that the REIP Surcharge proposed in Docket No. 2007-0416 is substantially similar to the CEI Surcharge and that the REIP Surcharge satisfies the Energy Agreement provision that the implementation procedure of the CEI Surcharge recovery mechanism be submitted for Commission approval by November 30, 2008. Because HECO considers the REIP and CEI surcharges to be one and the same, this document refers to this surcharge as the "REIP/CEI Surcharge."

Q. What surcharge recovery did the Company propose for AMI?

A. In its application for approval of the AMI project (Docket No. 2008-0303), the Company requested approval for recovery of the following incremental costs through the REIP/CEI Surcharge: accelerated cost recovery of new meters, accelerated cost recovery of existing non-AMI meters which will be taken out of service, meter data management system ("MDMS") hardware costs, deferral and amortization of MDMS software costs, MDMS expenses, network capital costs, lease expenses, and other expenses, offset by cost savings.

Q. What surcharge recovery will the Company propose for Big Wind Studies?

A. The Company intends to request recovery through the REIP/CEI Surcharge of certain non-labor outside services costs for the Big Wind Studies and some capital costs for equipment required for collecting data for the studies.

Q. How will the REIP/CEI Surcharge impact the Company's financial integrity?

A. The Company needs to raise additional funds for renewable infrastructure capital and deferred software development projects, while still continuing to make other investments required to maintain the reliability of the existing system. The Company's current capital expenditure budget is already significant given the aging infrastructure. The REIP/CEI Surcharge demonstrates timely ability to earn on and recover clean energy investment and expenses which is supportive of credit quality.

HECO needs to be able to raise the capital in the financial markets to construct and install these infrastructure projects without degrading credit quality, or increasing the cost of capital, either of which would be detrimental to ratepayers and the development of third-party renewable energy projects. The REIP/CEI Surcharge will demonstrate regulatory support and result in more immediate cost recovery which could reduce investors' perceptions of risk (although HECO would still need to raise the capital in the first place). This may help to maintain credit quality and cost of capital, and mitigate the potential degradation in credit quality caused by increasing capital requirements.

Q. Has S&P addressed electric utilities' rising capital expenditures in any of its reports?

A. Yes. For example, in a report dated March 9, 2009, S&P cautioned that, "Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs."[4] The report added that: "In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle." and "To the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures."

CHANGES IN ECONOMIC CONDITIONS

Q. Should the Company's authorized rate of return on common equity be reduced to 9.5%, as suggested by the cost of capital witnesses for the other Parties?

A. No, for the reasons stated by Dr. Morin in HECO RT-19. In addition, such a dramatic decrease would be particularly inappropriate at this time.

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[4] Standard & Poor's, RatingsDirect, Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings, March 9, 2009. (See HECO-R-2008.)

Q. How has the current financial and economic crisis impacted HECO?

A. As noted in Dr. Morin's response to DOD-IR-25, the utility industry has experienced a steady escalation in risk over the past ten years, as evidenced by the steady rise in utility betas, standard deviation of returns, bond downgrades, and other measures of risk. However, in these tough economic times in particular, investors are paying very close attention to the Company's ability to access cash.

HECO's BBB rating by S&P is of particular concern because that rating puts the Company only one notch above the minimum "investment grade credit rating". Prior to May 2007, S&P's corporate credit rating of HECO had been BBB+. In May 2007, S&P downgraded HECO to BBB. Reasons for the downgrade in 2007 included the continuous need for regulatory relief driven by heightened capital expenditure requirements. In May 2008, S&P maintained HECO's BBB credit rating, but lowered its business risk profile assessment from "excellent" to "strong". On November 26, 2008, S&P assigned a stable outlook to the BBB rating. As noted in my response to DOD-IR-39, under adverse economic conditions, companies with credit ratings below investment grade, or junk bond status, (i.e., below BBB-) may find it difficult, if not impossible, to raise new capital.

Accordingly, as noted in Mr. Fetter's response to CA-IR-21, instability in the financial markets in addition to the recessionary fears that currently exist about the U.S. economy lead to the conclusion that utilities operating within today's more stressful environment and their regulatory authorities should strive to minimize the regulatory uncertainties that could affect a utility's financial profile, its credit ratings, and thus its access to capital on favorable terms. With all the turmoil that has occurred within the electric utility sector, utilities and their regulators should strive to secure corporate ratings no lower than "BBB+/Baa1", with an ultimate goal of a rating within the "A" category.

Q. Has the economic downturn affected the cost of debt?

A. Yes. The spreads between A-rated utility versus ten-year T-Bonds increased from approximately 1.5% in January 2008 to as high as 4.0% in December 2008. The spreads between BBB-rated utility versus thirty-year T-Bonds increased from less that 2.0% in January 2008 to over 4.0% in December 2008.

Q. Has the economic downturn affected the cost of equity?

A. Yes. Despite a contracting economy, AUS's April 2009 Monthly Report reflected an average allowed ROE for Combined Electric/Combination Electric and Gas utilities of 10.75%, and according to Regulatory Research Associates' April 2, 2009 Regulatory Focus, the average electric utility equity return authorized by state commissions in the first three months of 2009 was 10.29%, as compared to the 10.46% average in calendar-2008. However, excluding a 8.75% equity return authorized for United Illuminating in Connecticut, the average was 10.48% in the first quarter, which is actually higher than the 2008 average.

Q. What is your general feeling regarding HECO's ROE under current economic conditions?

A. HECO's ROE should not be decreased during times of volatility and large bond spreads such as these, because of the risk of a potential downgrade. A downgrade of HECO's ratings would increase the Company's cost of capital, and thus, ultimately, the rates that customers are required to pay. The

Company must continue to obtain regulatory rulings that: (1) give the Company a realistic opportunity to earn a fair return, (2) provide full cost recovery of prudently incurred costs on which the Company's investors make no profit, (3) assure cost recovery of and on necessary capital investments, and (4) provide a fair return on prudent investments.

Q. Does any other commission share your view that in light of the current economy, the status quo should be maintained with respect to utility ROEs?

A. Yes. The Missouri Public Service Commission's January 27, 2009 decision in *Re Union Electric Company, dba AmerenUE*, Case No. ER-2008-031 provides a good example. In that rate case, the Missouri commission explained that: "Maintaining the status quo on the company's ROE in light of the economic circumstances and the U.S. credit crisis is the most prudent course of action. The U.S. credit crisis and ensuing breakdown in confidence among financial institutions has led to rising long-term borrowing rates. The freeze of the credit system causes concern for the utility's continued ability to provide financing for infrastructure investment needs, and then to continue to provide safe, reliable, and abundant power at reasonable rates. At this time, a cautious approach in changing the company's ROE is necessary to ensure investor confidence and company access to capital markets."

Q. Why is it critical to at least maintain HECO's current credit rating?

A. A financially stable utility will be able to invest in new renewable resources, infrastructure to facilitate the addition of new renewable resources from independent power producers, and conversion of the existing system to renewable technologies. The Company expects to enter into numerous new purchased power agreements for renewable energy, including power purchases under the feed-in tariff.

CONCLUSION

Q. What is your conclusion as to the appropriate rate of return on rate base to use in calculating revenue requirements in this docket?

A. The rate of return on its full rate base should not be less than the Company's composite cost of capital, and the Company's composite cost of capital in test year 2009 is 8.73%, including a rate of return on common equity of 11.0% (with the RBA and the RAM).

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

Composite Embedded Cost of Capital
Test Year 2009 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	WP Series Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	HECO-R-2002	$ -	0.00%		0.000%
Long-Term Debt	HECO-R-2003	576,569	40.76%	5.81%	2.368%
Hybrid Securities	HECO-2004	27,775	1.96%	7.41%	0.146%
Preferred Stock	HECO-R-2004	20,696	1.46%	5.48%	0.080%
Common Equity	HECO-R-2005	789,374	55.81%	11.00%	6.139%
Total Capitalization		$ 1,414,414	100.00%		8.733%
Estimated 2009 Test Year Composite Cost of Capital					**8.73%**

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Short-Term Borrowings
Test Year 2009 Average
($ Thousands)

	WP Reference	Total
Short-Term Borrowings as of December 31, 2008	RWP-2002, p.1	$ (8,450) (A)
2009 Estimated Net Change in Short-Term Borrowings	HECO-R-2006	(27,122)
Short-Term Borrowings as of December 31, 2009 [a]		$ (35,572) (B)
Test Year 2009 Average = [(A)+(B)]/2 [b]		**$ (22,011)**
Test Year 2009 Average Balance, Effective [b]		**$ -**
Earnings Requirement		
Annual Short-Term Debt Requirement		$ -

Notes:

a Totals may not add exactly due to rounding.

b The investment mode in short-term borrowings as of 12/31/08 and the further net decrease in short-term borrowings estimated for 2009 have resulted in the forecast short-term borrowings as of 12/31/09 also in an investment mode. For ratemaking purposes, HECO agreed to accept the Consumer Advocates position to eliminate the investment mode balance.

Hawaiian Electric Company, Inc.

Embedded Cost of Long-Term Debt
Test Year 2009 Average
($ Thousands)

Long-Term Debt	(A) Rate	(B) Net Proceeds	(C) = (A)*(B) Annual Interest	(D) = RWP-2003, p.2 Annual Amortization & Insurance Premium	(E) = (C)+(D) Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):					
Series 1993	5.45%	$ 50,000	$ 2,725	$ 89	$ 2,814
Series 1997A	5.65%	50,000	2,825	76	2,901
Refunding Series 1998A (1987)	4.95%	42,580	2,108	254	2,362
Refunding Series 1999B (1988)	5.75%	30,000	1,725	118	1,843
Series 1999C	6.20%	35,000	2,170	63	2,233
Refunding Series 1999D (1990A)	6.15%	16,000	984	115	1,099
Refunding Series 2000 (1990B&C)	5.70%	46,000	2,622	115	2,737
Series 2002A	5.10%	40,000	2,040	120	2,160
Refunding Series 2003B (1992)	5.00%	40,000	2,000	195	2,195
Refunding Series 2005A (1995A)	4.80%	40,000	1,920	158	2,078
Series 2007A	4.65%	100,000	4,650	127	4,777
Refunding Series 2007B (1996A&B)	4.60%	62,000	2,852	188	3,040
New Series 2009*	7.00%	45,000	3,150	16	3,166
		596,580	31,771	1,634	33,404
Unamortized Costs, Revenue Bonds **		(19,450)			
Unamortized Costs, First Mtg Bonds ***		(494)		67	67
Unamortized Costs, SCF ****		(67)		38	38
Test Year 2009 Average		**$ 576,569**	**$ 31,771**	**$ 1,738**	**$ 33,509**
Effective Rate = Total(F)/Total(B)					**5.81%**

* Planned 2009 long-term debt issuance has been updated from $60 million as reported in HECO-2003 to $90 million. Accordingly, the average test year balance has been updated from $30 million to $45 million. Additionally, the forecasted interest rate on the long-term debt has been updated from 6.50% as reported in HECO-2003 to 7.00%.

** Issuance costs, redemption costs, issuance discounts, and investment income differentials are included in this amount. Refer to RWP-2003, p.1 for detail.

*** Unamortized costs relate to HECO's First Mortgage Bonds which were redeemed prior to December 31, 2007. Refer to WP-2003, p.7 for First Mortgage Bonds unamortized costs.

**** Unamortized costs relate to HECO's share of the issuance costs for the Multi-year Syndicated Credit Facility (SCF). Refer to WP-2003, p. 8 for SCF issuance costs.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Embedded Cost of Preferred Stock
Test Year 2009 Average
($ Thousands)

		(A)	(B)	(C) = (A)*(B)	(D)	(E) = (C)+(D)
Preferred Stock		Rate	2009 Test Year Average	Annual Dividends	Annual Amortization	Annual Requirement
Perpetual Series: [a]						
Series C		4 1/4%	$ 3,000	$ 128	$ -	$ 128
Series D		5%	1,000	50	-	50
Series E		5%	3,000	150	-	150
Series H		5 1/4%	5,000	263	-	263
Series I		5%	1,793	90	-	90
Series J		4 3/4%	5,000	238	-	238
Series K		4.65%	3,500	163	-	163
	c		22,293	1,080	0	1,080
Unamortized Costs [b]			(1,597)		55	55
Test Year 2009 Average	c		**$ 20,696**	**$ 1,080**	**$ 55**	**$ 1,135**
Effective Rate = Total(E)/Total(B)						**5.48%**

Notes:

a The listing consists of preferred stock not subject to mandatory redemption. Therefore, issuance costs are not amortized. The list has been updated to eliminate the planned 2009 preferred stock issuance which was originally presented in HECO-2005.

b Refer to RWP-2004, p.1 for detail.

c Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Common Equity
2009 Average
($ Thousands)

	WP Reference		Total	
Book Common Equity as of December 31, 2008	RWP-2005, p.1	$	751,810	
Restoration	WP-2006 p.2		523	
Reversal of AOCI adj related to nonqualified plans			(812)	
Common Equity Investment as of December 31, 2008			751,520	(A)
Common Stock Issuance [a]			100,000	
Less: additional capital investments in subsidiaries				
Hawaii Electric Light Company, Inc.			(23,500)	
Maui Electric Company, Ltd.			(5,000)	
Renewable Hawaii, Inc.			(440)	
2009 Estimated Net Change in Retained Earnings	HECO-R-2006		4,648	
Common Equity as of December 31, 2009 [b]		$	827,228	(B)
Test Year 2009 Average = [(A)+(B)]/2		**$**	**789,374**	

Notes:

a Common stock issuance of $100 million expected in 2009.

b Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Sources and Applications of Funds
($ Thousands)

	Recorded 2008		Forecast 2009	
Application of Funds:				
Capital Expenditures	$	169,923	$	206,733
Less: CIAC & Advances		11,340		10,526
Less: AFUDC		9,269		14,271
Net Capital Expenditures	$	149,314	$	181,936
Debt Redemption	$	-	$	-
Hybrid Redemption		-		-
Investment in subsidiaries		100		28,940
Total Applications	$	149,414	$	210,876
Sources of Funds:				
Internal Sources:				
Retained Earnings	$	77,886	$	4,648
Depreciation & Amortization		87,263		89,732
Deferred Taxes & ITC		4,012		(6,313)
Other (Misc. Net Changes in Working Capital)		(31,513)		(40,069)
Total Internal Sources	$	137,648	$	47,998
External Sources:				
Increase (Decrease) in Short-Term Borrowings	$	-	$	(27,122)
Drawdown of Revenue Bond Proceeds		14,407		90,000
Common Stock Issuance		-		100,000
Temporary Investments		(2,641)		-
Total External Financing	$	11,766	$	162,878
Total Sources	$	149,414	$	210,876

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Financial Ratios Based on 11.0% Return on Equity

Test Year 2009

Based on **Strong** Business Risk Profile	RWP-2007 page ref.	AA	AA -	A +	A	A -	BBB +	BBB	BBB -	BB +	BB	BB -	B+
Financial Risk Profile		Minimal			Modest	Intermediate		HECO ↓	Aggressive			Highly Leveraged	
Rating		AA	AA -	A +	A	A -	BBB +	BBB	BBB -	BB +	BB	BB -	B+
		Investment Grade								Not Investment Grade			

WITHOUT Rate Relief (50% risk factor for puchased power obligations)

			AA	AA -	A +	A	A -	BBB +	BBB	BBB -	BB +	BB	BB -	B+
Funds from Operations / Average Total Debt	12%	p. 2									■			
Funds from Operations Interest Coverage	3.1 x	p.3							■					
Total Debt / Total Capital	56%	p. 4									□			

WITH Rate Relief (50% risk factor for puchased power obligations)

			AA	AA -	A +	A	A -	BBB +	BBB	BBB -	BB +	BB	BB -	B+
Funds from Operations / Average Total Debt	17%	p. 7								■				
Funds from Operations Interest Coverage	3.9 x	p. 8					■							
Total Debt / Total Capital	56%	p. 9									□			

WITH Rate Relief (25% risk factor for puchased power obligations)

			AA	AA -	A +	A	A -	BBB +	BBB	BBB -	BB +	BB	BB -	B+
Funds from Operations / Average Total Debt	21%	p. 11								■				
Funds from Operations Interest Coverage	4.6 x	p. 12			■									
Total Debt / Total Capital	50%	p. 13							□					

These ratios are based on the methodology used by S&P to calculate adjusted financial ratios for purposes of ratings analyses. The ratios take into account the debt equivalent (off-balance sheet purchased power and operating lease obligations). The rating guidelines are based on S&P's article "U. S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix" filed as HECO-2014. Based on the S&P matrix, HECO proportionately assigned rating categories to financial ratios as follows:

	Aggressive		
	BBB	**BBB-**	**BB+**
Funds from Operations / Average Total Debt	23.33% - 30%	16.67% - 23.33%	10% - 16.67%
Funds from Operations Interest Coverage	3.0x - 3.5x	2.5x - 3.0x	2.0x - 2.5x
Total Debt / Total Capital	45%-50%	50%-55%	55%-60%

	Intermediate			
	A	**A-**	**BBB+**	**BBB**
Funds from Operations / Average Total Debt	40% - 45%	35% - 40%	30% - 35%	25% - 30%
Funds from Operations Interest Coverage	4.13x - 4.5x	3.75x - 4.13x	3.38x - 3.75x	3.0x - 3.38x
Total Debt / Total Capital	35% - 38.75%	38.75% - 42.5%	42.5% - 46.25%	46.25% - 50%

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March 9, 2009

Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings

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Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings

Credit markets are tight. Liquidity is constrained. And construction, labor, and material costs are soaring. As if that weren't enough, the U.S. electric utility sector also faces aging infrastructure, declining capacity margins, and increasing environmental compliance requirements. To the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures. Although construction expenditure forecasts are temporarily lower due to deferrals of some projects, future spending needs will still be significant, especially in light of environmental requirements. And regulatory commissions reviewing material rate increase requests during a time of exceptional economic hardship might be very reluctant to approve higher electric base rates for consumers (as has occurred in Illinois, Michigan, and New York).

For these reasons, we believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality. That's why Standard & Poor's Ratings Services views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness.

Regulatory Risk

Regulators have historically set electricity rates that allow utilities to recover their operating costs and earn returns on equity. In our view, a key to the utility's credit quality is a strong, collaborative, and effective working relationship among management, regulators and, increasingly, elected officials to comprehensively vet and understand the risks associated with the utility's recovery of its investment. If the recession extends well into 2010, it is likely to have a credit drag on the sector, especially if utilities come under the inevitable cost scrutiny by regulators. Management's ability to manage this regulatory risk is a critical skill set.

Key factors in our analysis of the regulatory risk are the regulator's track record of consistency, stability, and predictability, as well as efficiency and timeliness. While we recognize the potential economic and political consequences of attempting to significantly raise utility rates during a recession, we believe that from credit perspective, management must work to limit uncertainty in the recovery of a utility's investment. In addition, we believe it must address the issue of rate case lag, especially when engaged in a sizable capital expenditure program. A regulatory jurisdiction that recognizes the importance of cash flow in its decision making process enhances the utility's creditworthiness.

Upon completion of a major project, while a phase-in or rate moderation plan may lessen the burden on the consumer and be more acceptable during an economic downturn, it may impair the utility's credit quality. Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs. In turn, this may necessitate a larger bank line that increases borrowing costs or increases debt levels to term out the short-term borrowings with medium-term notes, potentially increasing pressure on a company's financial profile. Hence, delayed revenue recovery is likely to be clearly more risky than traditional ratemaking treatment or rate mechanisms that provide timely rate recognition.

In our view, there are ratemaking alternatives that can eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in an onerous construction program. Instead of significantly large base rate increases or lengthy rate moderation or phase-in plans, separate tariff provisions that allow for timely rate recognition during construction, without requiring a utility to file a formal rate case application, can gradually ease higher costs into rates, limiting the accumulation of financing costs. Such provisions can also enhance cash flow and earnings stability.

Don't Forget The Fuel

Of primary importance to rating stability is limiting exposure to variations in fuel and purchased power costs, which constitute a utility's most significant expense. These expenses are largely out of utility management's control. Utilities that operate under rate moratoriums, fixed-fuel mechanisms, or significant regulatory lag, or without fuel and purchased-power adjustment clauses, are at risk for fluctuations in fuel and purchased power costs. As a result, they may be subject to reduced operating margins, and greater cash flow volatility and demand for working capital. Companies that are granted fuel true-ups may be required to stretch out recovery over many years to ease the pain for the consumer. There is no guarantee at some distant future date that collection of deferred revenues will occur. Changes in regulators, elected officials, and the economics of the service territory may render the promised recovery less certain.

Standard & Poor's notes that fuel adjustment clauses have become much more common in the utility industry, and several jurisdictions have recently reinstated previously abolished fuel clauses, but not all are created equal. While some states--such as Florida, Iowa, Kansas, and New York--permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions--such as Vermont and Washington State--impose deadbands in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. Cost recovery mechanisms that permit frequent updating of any estimated costs may help to keep any deferred balance to a relatively small amount.

Construction Is Accelerating

In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle. States such as Colorado, Idaho, Kansas, South Carolina (for nuclear facilities), North Dakota (for investments in transmission infrastructure and environmental compliance), and Wisconsin allow utilities to employ this credit-supportive ratemaking mechanism for certain projects. Allowing recovery of projected costs with subsequent periodic updates for actual results limits risk for fluctuating costs that occur between rate cases and reduces lags in cost recovery. Examples of less credit-supportive adjustment mechanisms include those that are triggered only after a company's incremental costs reach high thresholds (e.g. Washington) or those that, once triggered, force a company to accumulate significant deferrals before implementing a surcharge that results in real cash. Weak adjustment mechanisms may also cap accumulated deferrals or surcharges between rate cases.

In view of the risks associated with adding new base load capacity, utility managements are avoiding building facilities until absolutely necessary and only with binding regulatory assurances. From a credit perspective, we view the ability of the utility, commission staff, consumer advocates, and other major interveners to reach agreement on need, costs, and cost recovery before construction of new base load capacity as favorable. Iowa, Kansas, and Wisconsin have used preapproval or advance determination of the ratemaking principles for the recovery of certain investments, thereby potentially eliminating a large degree of uncertainty related to this issue.

An increasing number of regulatory jurisdictions are adopting tracking mechanisms and other riders that allow companies to adjust retail rates to reflect capital costs associated with environmental compliance equipment. These mechanisms eliminate the need to file a formal rate application to capture rate base additions and in many instances permit a return on, and of, capital on current and planned projects. Florida, Kansas, Indiana, Minnesota, and Texas are among those states that have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with emission controls.

Earnings and cash flow volatility potentially can be reduced and creditworthiness enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing extraordinary storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, we believe it has shown a willingness to work with utilities and has authorized increased charges to provide for the recovery of storm restoration expenses on a timely basis and to start replenishing storm reserves.

Rate mechanisms that mandate earnings sharing between shareholders and consumers compensate well run companies with a share of the profits when they earn more than their allowed return on equity. Accordingly, California has implemented an incentive framework that allows utilities to keep a portion of the net savings achieved under their energy efficiency programs. This gives an incentive to make the companies' operations more efficient. In some cases, sharing mechanisms also may provide downside protection to bondholders and can partially shield companies during troubled times by requiring consumers to foot the bill for a portion of lost earnings.

The ability to collect a consistent cash stream, regardless of a service area's weather conditions, provides an important level of stability. Several warmer-than-normal winters or cooler-than-normal summers could impair a utility's financial profile unless weather normalization measures are in place. Such protection can be achieved via a normalization clause or rate design. Some companies without such provisions have seen their financial profiles weaken partially in response to significant adverse weather conditions.

Some regulators and utilities want to significantly increase energy efficiency and conservation programs. Programs designed to separate earnings from delivered volumes (decoupling) can eliminate a current major disincentive for utilities to develop such conservation programs. Traditionally, when people use less electricity, utilities lose revenue. This would also theoretically align the interest of consumers and utilities by implementing innovative rate designs that would not discourage energy conservation and efficiency. For example, in 2008, the Massachusetts Department of Public Utilities issued a ruling that ordered utilities to pursue full decoupling in their next base rate case filings. The order is intended to encourage alternative energy resources and energy conservation and efficiency and to reduce costs without hurting a utility's bottom line.

There are a host of other rate mechanisms or special tariffs that regulatory jurisdictions apply to allow for timely recovery of costs including those associated with transmission, bad debt, property taxes, pensions, infrastructure or bare steel replacement, and legislatively mandated energy efficiency and renewable resource projects. Finally, the greater the percentage of a utility's rates that it recovers through fixed charges rather than volume-based charges, the greater the support for credit quality. And, given the current recession, the application of these various rate mechanisms and techniques, in our view, can be crucial in sustaining creditworthiness for the utility while potentially reducing the risk of evading significant rate increases or rate shock to the customer.

Note: Standard & Poor's recently published Assessments Of Regulatory Climates for U.S Investor-Owned Utilities (Nov. 25, 2008) has identified Alabama, California, Florida, Georgia, Indiana, Iowa, South Carolina, and Wisconsin, as those deemed 'more credit supportive', and Idaho, Kansas, and Kentucky among those 21 jurisdictions characterized as 'credit supportive'. We factored many of the aforementioned rate recovery mechanisms as well as other ratemaking and financial stability factors and political considerations into these assessments.

Hawaiian Electric Company, Inc.

Short-Term Borrowings
2008 Recorded

Account Description	General Ledger Account	12/31/08 Balance	
Notes Payable - MECO	233020	$	12,000,000
Notes Payable - HEI	233100	$	41,550,000
Commercial Paper	231010	$	-
Total Notes Payable		$	53,550,000
Total Notes Receivable - HELCO	145020	$	(62,000,000)
Total Short-Term Borrowings as of December 31, 2008, net		**$**	**(8,450,000)**

Hawaiian Electric Company, Inc.

Revenue Bonds
Summary of Unamortized Balances

Unamortized Costs	WP Reference	12/31/08 Unamortized Balance [a]	12/31/09 Unamortized Balance
Issuance and Redemption	RWP-2003, p.3	$ 14,227,251	$ 13,919,877
Investment Income Differential	RWP-2003, p.4	3,468,067	3,246,765
Issuance Discount	WP-2003 p.5	2,085,028	1,952,162
Total [b]		$ 19,780,346	$ 19,118,803
		(X)	(Y)
Test Year 2009 Average = [(X) + (Y)]/2			**$ 19,449,575**

Notes:

a The 2008 unamortized balances have been updated to reflect the actual recorded amounts.

b Totals may not add due to rounding

Hawaiian Electric Company, Inc.
Revenue Bonds
Summary of 2009 Annual Amortizations & Insurance

Series (Refunded Issue)	(A) = RWP-2003, p.3 Issuance and Redemption	(B) Annual Insurance	(C) = RWP-2003, p.4 Investment Income Differential	(D) = WP-2003, p.5 Discount	(E) = (A)+(B)+(C)+(D) Total
1993	$ 44,604		$ 10,665	$ 33,651	$ 88,919
1997A	13,822	45,000	17,037	-	75,859
Refunding 1998A	54,247		-	-	54,247
(1982)	45,762		35,977	-	81,739
(1987)	116,739		1,200	-	117,939
Refunding 1999B	39,627		-	17,953	57,580
(1988)	17,243		-	-	17,243
(1988 Conv)	43,030		-	-	43,030
1999C	37,330		26,168	-	63,498
Refunding 1999D	20,830		-	-	20,830
(1990A)	29,573		(1,162)	-	28,411
Refunding 2000	59,427		-	5,847	65,274
(1990B)	36,597		(399)	-	36,198
(1990C)	51,386		27,660	-	79,046
2002A	58,939		50,664	10,548	120,152
Refunding 2003B	78,137		-	-	78,137
(1992)	70,239		46,261	-	116,500
Refunding 2005A	82,056		-	-	82,056
(1995A)	48,914		1,281	25,784	75,978
2007A	123,481		3,384	-	126,865
Refunding 2007B	86,872		-	-	86,872
(1996A)	39,893		2,018	37,422	79,334
(1996B)	20,038		549	1,661	22,247
New Series 2009	15,600		-	-	15,600
Total	$ 1,234,387	$ 45,000	$ 221,303	$ 132,867	$ 1,633,556

Note:

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.
Revenue Bonds
Schedule of Issuing Expenses (Includes Amortization Differential)

Series (Refunded Issue)		(A) 2008 Annual Amortization	(B) 12/31/08 Unamortized Balance	(C) 2009 Annual Amortization	(D)=(B)-(C) 12/31/09 Unamortized Balance
1993		$ 44,604	$ 661,624	$ 44,604	$ 617,020
1997A		13,822	292,913	13,822	279,092
Refunding 1998A		54,247	176,304	54,247	122,057
(1982)		45,762	148,727	45,762	102,965
(1987)		116,739	379,400	116,739	262,661
Refunding 1999B		39,627	392,968	39,627	353,341
(1988)		17,243	597,710	17,243	537,436
(1988 Conv)		43,030	(incld. above)	43,030	(incld. above)
1999C		37,330	777,719	37,330	740,389
Refunding 1999D		20,830	229,134	20,830	208,304
(1990A)		29,573	325,303	29,573	295,730
Refunding 2000		59,427	683,413	59,427	623,986
(1990B)		36,597	420,868	36,597	384,271
(1990C)		51,386	612,347	51,386	560,961
2002A		58,939	1,394,888	58,939	1,335,948
Refunding 2003B		78,137	1,087,406	78,137	1,009,269
(1992)		70,239	977,506	70,239	907,267
Refunding 2005A		82,056	757,238	82,056	675,181
(1995A)		48,914	782,616	48,914	733,703
2007A		118,915	1,530,330	123,481	1,406,848
Refunding 2007B		86,872	939,358	86,872	852,486
(1996A)		39,893	691,483	39,893	651,589
(1996B)		20,038	359,011.32	20,038	338,973
New Series 2009	a	-	8,986	15,600	920,400
Total	b	$ 1,214,221	$ 14,227,251	$ 1,234,387	$ 13,919,877

Notes:

a Estimated issuance cost of $936,000 (1.04% of face) amortized over 360 months (30 year bond).

b Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.
Revenue Bonds
Schedule of Investment Income Differential

Series (Refunded Issue)	(A) Annual Amortization	(B) 12/31/08 Unamortized Balance	(C) 2009 Annual Amortization	(D)=(B)-(C) 12/31/09 Unamortized Balance
1993	$ 10,665	$ 158,189	$ 10,665	$ 147,525
1997A	17,037	319,442	17,037	302,405
Refunding 1998A	-	-	-	-
(1982)	35,977	116,926	35,977	80,948
(1987)	1,200.12	3,900	1,200	2,700
Refunding 1999B	-	-	-	-
(1988)	-	-	-	-
(1988 Conv)	-	-	-	-
1999C	26,168	545,176	26,168	519,007
Refunding 1999D	-	-	-	-
(1990A)	(1,162)	(12,781)	(1,162)	(11,619)
Refunding 2000	-	-	-	-
(1990B)	(399)	(4,593)	(399)	(4,193)
(1990C)	27,660	329,620	27,660	301,960
2002A	50,664	1,199,042	50,664	1,148,378
Refunding 2003B	-	-	-	-
(1992)	46,261	643,794	46,261	597,533
Refunding 2005A	-	-	-	-
(1995A)	1,281	20,494	1,281	19,213
2007A	79,883	104,046	3,384	100,662
Refunding 2007B	-	-	-	-
(1996A)	2,018	34,982	2,018	32,964
(1996B)	548.64	9,830	549	9,281
New Series 2009	-	-	-	-
Total	$ 297,802	$ 3,468,067	$ 221,303	$ 3,246,765

Note:

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Preferred Stock
Schedule of Issuance and Redemption Costs

Preferred Stock		Unamortized Balance G/L Account	(A) 2008 Annual Amortization	(B) 12/31/08 Unamortized Balance	(C) 2009 Annual Amortization	(D)=(B)-(C) 12/31/09 Unamortized Balance
Perpetual [a]						
Series C		21423000	$ -	$ 70,404	$ -	$ 70,404
Series D		21424000	-	55,071	-	55,071
Series E		21425000	-	183,556	-	183,556
Series H		21428000	-	59,679	-	59,679
Series I		21429000	-	64,701	-	64,701
Series J		21430000	-	49,654	-	49,654
Series K		21431000	-	39,755	-	39,755
Subtotal	c		-	522,820	-	522,820
Redeemed: [b]						
Series M		18674M00	7,110	142,208	7,110	135,098
Series Q		18674Q00	28,154	563,091	28,154	534,937
Series R		18674R00	19,821	396,420	19,821	376,599
Subtotal	c		55,085	1,101,718	55,085	1,046,633
Total	c		$ 55,085	$ 1,624,538 (X)	$ 55,085	$ 1,569,453 (Y)
Test Year 2009 Average = [(X) + (Y)]/2						**$ 1,596,996**

Notes:

a The list consists of preferred stock not subject to mandatory redemption. As such, issuance costs are not amortized.

b Amortization expense recorded to G/L Account Code #42501000.

c Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Common Equity
2008 Recorded

Account Description	G/L Account		12/31/08 Balance	
Common Stock Issued	20100000	$	85,387,140	
Premium on Capital Stock	20700000		303,135,446	
Misc Paid in Capital	211		1,650,978	
Capital Stock Expense - Common	21401000		(3,526,923)	
Preferred Stock Expense	2143		(394,693)	
Net Income for Common	n/a		-	closed to Retained Earnings
Retained Earnings	216		802,590,542	
Dividends, net	43800000		-	closed to Retained Earnings
Common Stock Equity of HECO		$	1,188,842,490	
Investment in Subsidiary - MECO	12301000	$	(215,381,379)	
Investment in Subsidiary - HELCO	12302000		(221,405,040)	
Investment in Subsidiary - UBC	12303000		(141,470)	
Investment in Subsidiary - RHI	12306000		(105,088)	
Investment in Subsidiaries *		$	(437,032,977)	
Common Equity as of December 31, 2008		$	751,809,513	

* Does not include $1,546,400 of equity investment in the HECO Capital Trust III (Capital Trust) subsidiary. The investment in the Capital Trust is offset against HECO's Hybrid securities which were purchased by the Capital Trust.

Hawaiian Electric Company, Inc.
Test Year 2009

Income Statement
NO Rate Increase (Current Rates) & WITH Debt Equivalent
Based on 11.0% Earned Return on Common Equity

	$ in thousands	HECO Reference
Operating Income	61,067	Per calculation from Budgets Division
AFUDC	7,899	Note 1
Annual Debt Requirement:		
Short-term Debt	0	R-2002
Long-term Debt	33,509	R-2003
Hybrid	2,059	2004
Total Annual Debt Requirement	35,568	
Net Income	33,398	
Annual requirement on Preferred Stock	1,135	R-2004
Net Income for Common	32,263	

Note 1: AFUDC per HECO-2007 of $14,271, less AFUDC for CIP1.

Total AFUDC	14,271	R-2006
Less: AFUDC - CIP1	6,372	
AFUDC - Other	7,899	

Hawaiian Electric Company, Inc.
Test Year 2009

Funds from Operations / Average Total Debt
NO Rate Increase (Current Rates) & WITH Debt Equivalent
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	61,067		Per calculation from Budgets Division
Depreciation	81,868		Per calculation from Budgets Division
Depreciation adjustment for Operating Leases	1,840		Per calculation from Budgets Division
Deferred Income Taxes	24,041		Statement of Probable Entitlement Exhibit 1 p.12
Amortization of State ITC	(1,453)		Per calculation from Budgets Division
State Capital Goods Excise Credit	0		Per calculation from Budgets Division
Interest Expense:			
Short-term interest	0		R-2002
Long-term interest	(31,771)		R-2003
Hybrid interest	(2,051)		2004
Total Interest Expense	(33,822)		
Total	133,541	A	
Average Debt:			
Short-term Debt	0		R-2002
Long-term Debt[1]	595,620		R-2003 & WP-2003, p.5
Hybrid[2]	31,546		2004
OBS Debt (50%) - Purch Pwr Commitments[3]	431,033		WP-2016, p. 14
OBS Debt - Operating Leases[3]	17,289		Per calculation from Budgets Division
Average Total Debt	1,075,488	B	
FFO to Ave Total Debt Ratio (A)/(B)	12%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2009

Funds from Operations Interest Coverage
NO Rate Increase (Current Rates) & WITH Debt Equivalent
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	61,067		Per calculation from Budgets Division
Depreciation	81,868		Per calculation from Budgets Division
Deferred Income Taxes	24,041		Per calculation from Budgets Division
Amortization of State ITC	(1,453)		Per calculation from Budgets Division
State Capital Goods Excise Credit	0		Per calculation from Budgets Division
Interest on OBS Debt - Purchased Power Commitments [1]	25,448		WP-2016, p. 14
Interest on OBS Debt - Operating Leases [1]	1,037		Per calculation from Budgets Division
Total	192,008	A	
Total Debt Requirement (ST, LT & Hybrids)	35,568		RWP-2007, p. 1
Interest on OBS Debt - Purchased Power Commitments [1]	25,448		WP-2016, p. 14
Interest on OBS Debt - Operating Leases [1]	1,037		Per calculation from Budgets Division
	62,053	B	
Fund from Operations Interest Coverage (A)/(B)	3.1	x	

[1] Interest on off-balance sheet (OBS) debt is not reflected in the book numbers. Interests on the OBS debt related to purchased power commitments and operating leases represent the interest expense that the Company would have incurred if the debt equivalent related to purchased power commitments and operating leases were reflected as a debt obligation on the Company's balance sheet.

Hawaiian Electric Company, Inc.
Test Year 2009

Total Debt / Total Capital
NO Rate Increase (Current Rates) & WITH Debt Equivalent
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	(35,572)		R-2002
Long-term Debt [1]	640,654		R-2003 & WP-2003, p.5
Hybrid Securities [2]	31,546		2004
Total Debt	636,628		
OBS Debt (50%) - Purch Pwr Commitments [3]	424,136		WP-2016, p. 14
OBS Debt - Operating Leases [3]	16,331		Per calculation from Budgets Division
Pension Obligation	0		No estimate available
Equity Adjustment for Hybrids	(15,773)		50% of YE balance
Debt Adjustment for Preferred Stock	11,147		50% of YE balance
Revised Total Debt	1,072,469	A	
Preferred Stock [2]	22,293		R-2004
Common Stock	827,228		R-2005
Debt Adjustment for Preferred Stock	(11,147)		50% of YE balance
Equity Adjustment for Hybrids	15,773		50% of YE balance
Total Capital	1,926,616	B	
Total Debt / Total Capital Ratio (A)/(B)	56%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2009

Total Debt / Total Capital
NO Rate Increase & WITHOUT Purchased Power Debt Equivalent
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	(35,572)		R-2002
Long-term Debt [1]	640,654		R-2003 & WP-2003, p.5
Hybrid Securities [2]	31,546		2004
Total Debt	636,628		
OBS Debt (50%) - Purch Pwr Commitments [3]	0		
OBS Debt - Operating Leases [3]	16,331		Per calculation from Budgets Division
Pension Obligation	0		No estimate available
Equity Adjustment for Hybrids	(15,773)		50% of YE balance
Debt Adjustment for Preferred Stock	11,147		50% of YE balance
Revised Total Debt	648,333	A	
Preferred Stock [2]	22,293		R-2004
Common Stock	827,228		R-2005
Debt Adjustment for Preferred Stock	(11,147)		50% of YE balance
Equity Adjustment for Hybrids	15,773		50% of YE balance
Total Capital	1,502,480	B	
Total Debt / Total Capital Ratio (A)/(B)	43%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2007

Income Statement
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (50% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands	HECO Reference
Operating Income	109,372	Per calculation from Budgets Division
AFUDC	7,899	Note 1
Annual Debt Requirement:		
Short-term Debt	0	R-2002
Long-term Debt	33,509	R-2003
Hybrid	2,059	2004
Total Annual Debt Requirement	35,568	
Net Income	81,703	
Annual requirement on Preferred Stock	1,135	R-2004
Net Income for Common	80,568	

Note 1: AFUDC per HECO-2007 of $14,271, less AFUDC for CIP1.

Total AFUDC	14,271	R-2006
Less: AFUDC - CIP1	6,372	
AFUDC - Other	7,899	

Hawaiian Electric Company, Inc.
Test Year 2009

Funds from Operations / Average Total Debt
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (50% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	109,372		Per calculation from Budgets Division
Depreciation	81,868		Per calculation from Budgets Division
Depreciation adjustment for Operating Leases	1,840		Per calculation from Budgets Division
Deferred Income Taxes	24,041		Per calculation from Budgets Division
Amortization of State ITC	(1,453)		Per calculation from Budgets Division
State Capital Goods Excise Credit	0		Per calculation from Budgets Division
Interest Expense:			
Short-term interest	0		R-2002
Long-term interest	(31,771)		R-2003
Hybrid interest	(2,051)		2004
Total Interest Expense	(33,822)		
Total	181,846	A	
Average Debt:			
Short-term Debt	0		R-2002
Long-term Debt[1]	595,620		R-2003 & WP-2003, p.5
Hybrid[2]	31,546		2004
OBS Debt (50%) - Purch Pwr Commitments[3]	431,033		WP-2016, p. 14
OBS Debt - Operating Leases[3]	17,289		Per calculation from Budgets Division
Average Total Debt	1,075,488	B	
FFO to Ave Total Debt Ratio (A)/(B)	17%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2009

Funds from Operations Interest Coverage
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (50% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	109,372		Per calculation from Budgets Division
Depreciation	81,868		Per calculation from Budgets Division
Deferred Income Taxes	24,041		Per calculation from Budgets Division
Amortization of State ITC	(1,453)		Per calculation from Budgets Division
State Capital Goods Excise Credit	0		Per calculation from Budgets Division
Interest on OBS Debt - Purchased Power Commitments[1]	25,448		WP-2016, p. 14
Interest on OBS Debt - Operating Leases[1]	1,037		Per calculation from Budgets Division
Total	240,313	A	
Total Debt Requirement (ST, LT & Hybrids)	35,568		RWP-2007, p. 1
Interest on OBS Debt - Purchased Power Commitments[1]	25,448		WP-2016, p. 14
Interest on OBS Debt - Operating Leases[1]	1,037		Per calculation from Budgets Division
	62,053	B	
Fund from Operations Interest Coverage (A)/(B)	3.9	x	

1

Interest on off-balance sheet (OBS) debt is not reflected in the book numbers. Interests on the OBS debt related to purchased power commitments and operating leases represent the interest expense that the Company would have incurred if the debt equivalent relate to purchased power commitments and operating leases were reflected as a debt obligation on the Company's balance sheet.

Hawaiian Electric Company, Inc.
Test Year 2009

Total Debt / Total Capital
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (50% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	(35,572)		R-2002
Long-term Debt [1]	640,654		R-2003 & WP-2003, p.5
Hybrid Securities [2]	31,546		2004
Total Debt	636,628		
OBS Debt (50%) - Purch Pwr Commitments [3]	424,136		WP-2016, p. 14
OBS Debt - Operating Leases [3]	16,331		Per calculation from Budgets Division
Pension Obligation	0		No estimate available
Equity Adjustment for Hybrids	(15,773)		50% of YE balance
Debt Adjustment for Preferred Stock	11,147		50% of YE balance
Revised Total Debt	1,072,469	A	
Preferred Stock [2]	22,293		R-2004
Common Stock	827,228		R-2005
Debt Adjustment for Preferred Stock	(11,147)		50% of YE balance
Equity Adjustment for Hybrids	15,773		50% of YE balance
Total Capital	1,926,616	B	
Total Debt / Total Capital Ratio (A)/(B)	56%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2009

Total Debt / Total Capital
WITH Rate Increase (CIP1 Generating Unit Step) & WITHOUT Purchased Power Debt Equivalent
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	(35,572)		R-2002
Long-term Debt [1]	640,654		R-2003 & WP-2003, p.5
Hybrid Securities [2]	31,546		2004
Total Debt	636,628		
OBS Debt (50%) - Purch Pwr Commitments [3]	0		
OBS Debt - Operating Leases [3]	16,331		Per calculation from Budgets Division
Pension Obligation	0		No estimate available
Equity Adjustment for Hybrids	(15,773)		50% of YE balance
Debt Adjustment for Preferred Stock	11,147		50% of YE balance
Revised Total Debt	648,333	A	
Preferred Stock [2]	22,293		R-2004
Common Stock	827,228		R-2005
Debt Adjustment for Preferred Stock	(11,147)		50% of YE balance
Equity Adjustment for Hybrids	15,773		50% of YE balance
Total Capital	1,502,480	B	
Total Debt / Total Capital Ratio (A)/(B)	43%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2009

Funds from Operations / Average Total Debt
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (25% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	109,372		Per calculation from Budgets Division
Depreciation	81,868		Per calculation from Budgets Division
Depreciation adjustment for Operating Leases	1,840		Per calculation from Budgets Division
Deferred Income Taxes	24,041		Per calculation from Budgets Division
Amortization of State ITC	(1,453)		Per calculation from Budgets Division
State Capital Goods Excise Credit	0		Per calculation from Budgets Division
Interest Expense:			
Short-term interest	0		R-2002
Long-term interest	(31,771)		R-2003
Hybrid interest	(2,051)		2004
Total Interest Expense	(33,822)		
Total	181,846	A	
Average Debt:			
Short-term Debt	0		R-2002
Long-term Debt [1]	595,620		R-2003 & WP-2003, p.5
Hybrid [2]	31,546		2004
OBS Debt (25%) - Purch Pwr Commitments [3]	215,517		WP-2016, p. 14
OBS Debt - Operating Leases [3]	17,289		Per calculation from Budgets Division
Average Total Debt	859,971	B	
FFO to Ave Total Debt Ratio (A)/(B)	$\boxed{21\%}$		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Hawaiian Electric Company, Inc.
Test Year 2009

Funds from Operations Interest Coverage
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (25% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	109,372		Per calculation from Budgets Division
Depreciation	81,868		Per calculation from Budgets Division
Deferred Income Taxes	24,041		Per calculation from Budgets Division
Amortization of State ITC	(1,453)		Per calculation from Budgets Division
State Capital Goods Excise Credit	0		Per calculation from Budgets Division
Interest on OBS Debt - Purchased Power Commitments[1]	12,724		WP-2016, p. 14
Interest on OBS Debt - Operating Leases[1]	1,037		Per calculation from Budgets Division
Total	227,589	A	
Total Debt Requirement (ST, LT & Hybrids)	35,568		WP-2013, p. 1
Interest on OBS Debt - Purchased Power Commitments[1]	12,724		WP-2016, p. 14
Interest on OBS Debt - Operating Leases[1]	1,037		Per calculation from Budgets Division
	49,329	B	
Fund from Operations Interest Coverage (A)/(B)	4.6	x	

[1] Interest on off-balance sheet (OBS) debt is not reflected in the book numbers.
Interest on the OBS debt related to purchased power commitments and operating leases represents the interest expense that the Company would have incurred if the debt equivalent related to purchased power commitments and operating leases were reflected as a debt obligation on the Company's balance sheet.

Hawaiian Electric Company, Inc.
Test Year 2009

Total Debt / Total Capital
WITH Rate Increase (CIP1 Generating Unit Step) & WITH Debt Equivalent (25% Risk Factor)
Based on 11.0% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	(35,572)		R-2002
Long-term Debt [1]	640,654		R-2003 & WP-2003, p.5
Hybrid Securities [2]	31,546		2004
Total Debt	636,628		
OBS Debt (25%) - Purch Pwr Commitments [3]	212,068		WP-2016, p. 14
OBS Debt - Operating Leases [3]	16,331		Per calculation from Budgets Division
Pension Obligation	0		No estimate available
Equity Adjustment for Hybrids	(15,773)		50% of YE balance
Debt Adjustment for Preferred Stock	11,147		50% of YE balance
Revised Total Debt	860,401	A	
Preferred Stock [2]	22,293		R-2004
Common Stock	827,228		R-2005
Debt Adjustment for Preferred Stock	(11,147)		50% of YE balance
Equity Adjustment for Hybrids	15,773		50% of YE balance
Total Capital	1,714,548	B	
Total Debt / Total Capital Ratio (A)/(B)	50%		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

REBUTTAL TESTIMONY OF
STEVEN M. FETTER

On Behalf of

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Financial Integrity

INTRODUCTION

Q. Please state your name, address, and occupation.

A. My name is Steven M. Fetter. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, NV 89014. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002.

Q. Are you the same Steven M. Fetter who filed direct testimony in this docket on July 3, 2008?

A. Yes, I am.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this rebuttal testimony to the Hawaii Public Utilities Commission (the "Commission") on behalf of Hawaiian Electric Company ("HECO" or the "Company").

Q. What is the purpose of your rebuttal testimony?

A. My testimony will address return on equity ("ROE") recommendations made within this docket by Mr. Steven G. Hill, on behalf of the Department of Defense, and Mr. David C. Parcell, on behalf of the Division of Consumer Advocacy. Specifically, Mr. Hill proposes an authorized ROE for HECO of 9.50% and Mr. Parcell proposes an authorized ROE at the lower end of his recommended range of 9.50% to 10.50%. I will explain that these recommendations fall near the bottom of ROEs ordered for electric utilities across the U.S. during 2009, and that the 11.00% to 11.25% ROE that HECO witness Dr. Roger Morin recommends in his rebuttal testimony for the Company operating with a revenue decoupling mechanism is more appropriate under the financial crisis conditions that now prevail within the U.S. economy. I also discuss the appropriate impact that purchased power adjustment mechanisms ("PPACs") and revenue decoupling should have on the ROE that the Commission will be authorizing for HECO in this proceeding.

Q. Could you begin by discussing the current trend in ROE findings by public utility commissions across the U.S.?

A. Yes. For the past three years, authorized ROEs for regulated electric utilities have slowly moved upward from among the lowest levels ordered by state utility regulators during the past two decades – tracking at 10.29% for 2006, 10.32% in 2007, and 10.34% during 2008.[1] Not surprisingly, after the global financial collapse during the Fall of 2008, early signs in 2009 point to higher authorized ROEs to help ensure the financial stability of regulated utilities, especially those which, like HECO, hold credit ratings within the "BBB" category.

Q. Please explain.

A. First with regard to regulatory ROE decisions, I have attached exhibit HECO-R-2101 which lists the 12 electric utility ROE findings reported by SNL Regulatory Research Associates for the first four months of 2009. As can be seen, the 9.50% recommendation by Mr. Hill and near 9.50% recommendation by Mr. Parcell fall at the bottom of the list. The average for

[1] Edison Electric Institute, 2008 Financial Review at p. 34.

the twelve decisions exceeds 10.50% and tracks more closely with Dr. Morin's 11.00% to 11.25% recommendation. Indeed, the six most recent regulatory determinations decided in March and April 2009 average 10.77%.

Q. You also refer to the current financial crisis. Does the ongoing economic stress faced by all utilities enter into your view of HECO as it prepares to implement the components of the settlement agreement if approved by the Commission?

A. Yes, especially since HECO holds ratings within the 'BBB' category. With the capital markets currently experiencing an historic, worldwide financial melt-down with a resulting severe economic recession, I believe it is important for regulators to factor into their decision-making the negative stresses that regulated utilities within the 'BBB' category are currently facing. The U.S. stock market experienced its third-worst year in more than a century in 2008, with the S&P 500 and the Dow Jones Industrial Average down 38.5% and 33.8%, respectively. No fewer than fifteen U.S. banks failed in 2008, including the well-publicized bankruptcy of Lehman Brothers on September 15, 2008, the largest bankruptcy in U.S. history. The changes on Wall Street mean that there will be less capital available for companies seeking debt and equity financing – and, unlike the broader corporate industrial sector which can delay capital investment in times of duress, electric utilities carry a public responsibility to expend capital when needed to ensure safe and reliable service to customers.

I understand that the recent economic turmoil resulted in some utilities within the 'BBB' category experiencing difficulty in accessing the capital markets at any cost. Even when capital is available, it is often at significantly higher costs and upon less favorable terms and conditions. As Moody's reported in a January 16, 2009 report entitled, "Near-term Bank Credit Facility Renewals To Be More Challenging For U.S. Investor-Owned Electric and Gas Utilities":

> Dramatic changes in the financial markets during 2008 have materially changed the banking environment for utilities going forward, which will make upcoming credit facility renewals significantly more challenging. . . . Those banks that do remain will be constrained in both their ability and inclination to provide traditional credit, especially at the relatively low pricing levels and on the liberal terms and conditions that prevailed prior to mid-2008.

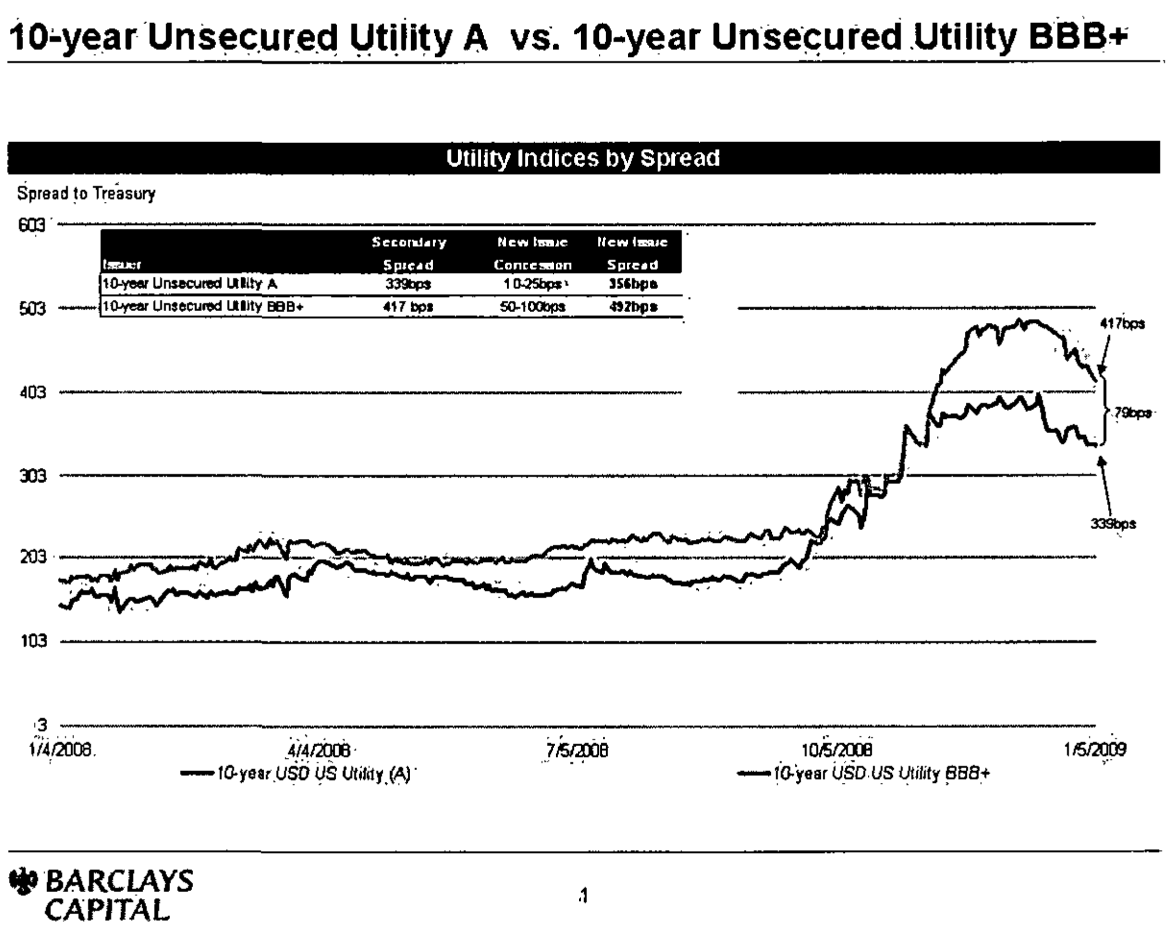
Q. Have other industry leaders offered similar cautions?

A. Yes. During the January 13, 2009 Federal Energy Regulatory Commission ("FERC") Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, regulators, industry representatives, and banks all agreed that the financial crisis is having a more dramatic impact on lower rated utilities. W. Paul Bowers, the Executive Vice President and Chief Financial Officer of Southern Company, noted that although the financial crisis has led to increases in debt and equity risk premiums for all utilities, these increases have been more consistently applied to utilities that do not hold high credit ratings, resulting in significantly higher cost of debt capital for 'BBB' category utilities as compared to 'A' rated utilities. Mr. Bowers' views were supported by data presented by Anthony Ianno, Managing Director and Head of Energy & Utilities Global Risk Capital Markets at Morgan Stanley, which showed that investment in 'BBB' rated utilities dropped approximately 13% in the period after the Lehman Brothers bankruptcy, while investment in 'A' rated utilities rose by the same margin. Such data clearly show that, in the wake of the financial crisis, investor interest has been increasingly directed toward less risky 'A' rated utilities. As Chairman Garry Brown of the New York Public Service Commission ("NYPSC") noted at the FERC conference, "there is a clear relationship between a utility's bond rating and its ability to borrow at a reasonable cost, particularly in times of economic distress as we are now facing."

As I alluded to earlier, electric utilities do not possess the strategic option of substantially cutting back their core operations during difficult economic times. Despite facing the reality of having rates out of line with decreasing sales, as well as growing uncollectible billed amounts, utilities must provide safe, efficient, and reliable service to their customers notwithstanding dysfunction within the financial markets. The electric utility sector is one of the most capital-intensive sectors in the country, and utilities must continue to make significant capital expenditures to maintain reliability, replace aging infrastructure, and meet longer-term load growth requirements. As NYPSC Chairman Brown further noted, "Large capital programs . . . make it very important that electric utilities continue to have access to the financial markets, and regulatory policies should support utilities' ability to raise capital."

Q. Can you share specifics about the particular financial stresses that 'BBB' rated utilities have faced?

A. Yes. Since September 2008, yield spreads on bonds with default risk have moved significantly higher, as opposed to falling yields on U.S. Treasury bonds ("Treasuries").



Source: Barclay's Capital, Chart: *10-year Unsecured Utility A vs. 10-year Unsecured Utility BBB+*, as of January 5, 2009.

The chart above shows that for 10-year unsecured utility debt, by the end of 2008, the spread over Treasuries for new issues became 356 basis points for 'A' rated debt and 492 basis points for 'BBB+' rated debt. This compares to similar debt that six months earlier was trading slightly below ('A' rated) or above ('BBB+' rated) 200 basis points over Treasuries. Moreover, with regard to longer-term debt, a comparison of basis point spreads between 'A' and 'Baa' rated Moody's utility bond indices and 30-year Treasuries shows a widening of spreads at an alarming rate since the beginning of the financial crisis. In December 2007, the amount over Treasuries for 'A' rated utility bonds was 163 basis points, and the amount over Treasuries for 'Baa' rated utility bonds was 198 basis points. As of December 2008, the amount over Treasuries for 'A' rated utility bonds was 365 basis points, and the amount over Treasuries for 'Baa' rated utility bonds was 524 basis points. The difference between 'A' and 'Baa' rated utility bond yields thus totaled 159 basis points (a growth of 124 basis points since December 2007).[2]

Q. Hasn't the situation improved since the end of 2008?

A. While spreads have tightened since the end of 2008, volatility in the equity markets remains high. What I believe is important to take away from capital market events over the past year is that the negative effects from the current financial crisis on the overall economy will not be transitory nor quick to turn

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[2] Data from U.S. Treasury Department, Mergent Bond Record, and Bloomberg.

around. And the utility sector, even if positively "stimulated" with federally supported infrastructure spending, must still deal with delinquent accounts and uncollectibles growing across virtually the entire regulated energy sector, deeply eroded pension plan values, soaring health care funding requirements, and financing activity that is subject to greater volatility with regard to both availability and cost. The negative events during the Fall of 2008 illustrate clearly that 'BBB' category utilities are much more vulnerable than 'A' category utilities when capital markets are in a state of upheaval.

Q. The settlement agreement includes a PPAC. Do you believe that the ROE authorized for HECO should be reduced if such mechanism is approved?

A. No I do not. Existence of a PPAC is the mainstream position for regulated utilities across the U.S., with regulators in approximately 40 states utilizing some form of PPAC.[3] Thus, the ROE analysis undertaken by Dr. Morin (and indeed Mr. Hill and Mr. Parcell also) largely factors in the presence of such an adjustment mechanism. Accordingly, if the Commission were to lower HECO's authorized ROE to reflect the implementation of a PPAC, it would be punishing HECO for its PPAC vis-à-vis its industry peers, most of whom also operate with some form of PPAC.

Q. How do you view revenue decoupling and its potential effect on authorized ROEs?

[3] "Fuel and Wholesale Power Cost Recovery," SNL - Regulatory Research Associates, October 3, 2005.

A. I agree with the rating agencies' positive orientation toward revenue decoupling. As S&P has noted:

> Decoupling is a mechanism that severs the relationship between sales and revenues, thereby allowing a utility to earn a predetermined level of distribution revenue regardless of the actual kWh sold. ...This mechanism removes the disincentive for utilities to conserve, and allows a utility to execute an energy plan of either supply growth or demand reduction based on solid economics and/or other policy issues. ...[S&P] views decoupling as a positive development from a credit perspective. Decoupling allows utilities to project cash flow more accurately and avoid much of the earnings volatility from changes to weather/economy under traditional rate mechanism.[4]

That said, I view revenue decoupling differently than I view PPACs. Unlike PPACs, decoupling is not yet the norm for regulated utilities across the U.S. – the Wall Street Journal recently reported that "at least a dozen states, including New York, North Carolina and California, have decoupling measures in place, while 26 others -- from Maine to Idaho and Nevada -- are reviewing or implementing them."[5] I do not believe that decoupling has reached sufficient critical mass whereby it would inherently be captured by traditional ROE analysis. Accordingly, I believe a lowering of authorized ROE is appropriate if revenue decoupling is approved here. A 25 basis point reduction, as proposed by Dr. Morin, seems to be the right correction, while Mr. Parcell's proposed 50 basis point drop seems too significant a downward

[4] S&P Research: "Decoupling: The Vehicle for Energy Conservation?," February 19, 2008.
[5] "Less Demand, Same Great Revenue," Wall Street Journal, February 8, 2009.

move for a policy that is strongly supported by many environmentalists and elected and appointed policymakers.

Q. Is it a given that the rating agencies will monitor the Commission's response to the pending settlement agreement and its determination of HECO's authorized ROE?

A. Yes. S&P highlighted the continuing importance of regulation to the financial community in a November 26, 2008 report entitled "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry":

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Consistent with these views, S&P recently explained how recovery mechanisms, such as the PPAC proposed within the settlement agreement, can play a key role in providing a regulated utility with timely recovery of prudent expenditures, thereby helping to mitigate the negative effects from regulatory lag:

> ...we believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit

> quality. That's why [S&P] views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness.[6]

Q. Is it reasonable to expect that these general statements about the importance of regulation find specific applicability with regard to the policies of this Commission?

A. Yes, very much so. Virtually every time a rating agency modifies or affirms a utility credit rating, mention is made of the regulatory body within the relevant jurisdiction and how its policies are factored into the rating determination. A positive perception of regulation within a utility's jurisdiction by the financial community is factored into credit rating analysis and can assist a company in maintaining or improving its credit ratings. S&P's current assessment of the Hawaii Commission is in the middle of the pack – ranked behind 20% of all state commissions and higher than 40% of other state commissions, in a category entitled "Credit Supportive".[7]

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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[6] S&P Research: "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings," March 9, 2009. (See HECO-R-2008.)

[7] S&P Research: "Credit FAQ: Standard & Poor's Assessments of Regulatory Climates for U.S. Investor-Owned Utilities," November 25, 2008.

SUMMARY of ROEs in Electric Utility Rate Cases Decided in 2009

[where specified by SNL Regulatory Research Associates]

Company	Date Approved	ROE Allowed (%)
Southern California Edison	3/12/2009	11.50
Tampa Electric	3/17/2009	11.25
Dr. Roger Morin w/decoupling		**11.00 - 11.25**
Union Electric	1/27/2009	10.76
ALLETE (Minn. Pwr.)	4/3/2009	10.74
Pacificorp (Utah)	4/21/2009	10.61
Mr. Parcell (top of range)		**10.50**
Cleveland Electric Illuminating	1/21/2009	10.50
Idaho Power	1/30/2009	10.50
Indiana Michigan Power	3/4/2009	10.50
Ohio Edison	1/21/2009	10.50
Toledo Edison	1/21/2009	10.50
Consolidated Edison	4/21/2009	10.00
Mr. Parcell (bottom of range)		**9.50**
Mr. Hill		**9.50**
United Illuminating	2/4/2009	8.75

HECO RT-23
DOCKET NO. 2008-0083

TESTIMONY OF
TAYNE S. Y. SEKIMURA

SENIOR VICE PRESIDENT
FINANCE AND ADMINISTRATION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Results of Operations, including Revenue Requirements, Rate Increase Implementation, and Summary

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Senior Vice President, Finance and Administration, for Hawaiian Electric Company, Inc. ("HECO" or "Company"). My educational background and professional experience has been previously provided in HECO-2000.

Q. What testimony will you give in HECO RT-23?

A. My testimony in HECO RT-23 addresses HECO's Results of Operations, including revenue requirements for test year 2009, and proposed implementation of the requested increase.

RESULTS OF OPERATIONS

Q. What results of operations scenarios for test year 2009 are included in your testimony and exhibits?

A. My testimony and exhibits include four test year 2009 Results of Operations scenarios:

1) Results of Operations at 11.00% ROE, with informational advertising
2) Results of Operations at 11.00% ROE, without informational advertising
3) Results of Operations at 11.25% ROE, with informational advertising
4) Results of Operations at 11/25% ROE, without informational advertising

Q. What revenue requirements are reflected in HECO's test year 2009 Results of Operations at 11.00% return on common equity, with informational advertising?

A. HECO's test year 2009 Results of Operations at 11.00% return on common equity, with informational advertising expenses included, reflects a revenue requirement of $1,383,153,000 (based on December 2008 fuel oil and purchased energy prices) to produce an 8.73% return on HECO's test year 2009 rate base of $1,252,830,000 at proposed rates, as shown in HECO-R-2301. At "current effective rates", HECO's test year 2009 Results of Operations with informational advertising expenses included, reflect total operating revenues of $1,296,374,000 (based on December 2008 fuel oil and purchased energy prices) for test year 2009, or $86,779,000 less than the test year 2009 revenue requirements at 11.00 % return on common equity, including informational advertising, proposed by HECO, as shown in HECO-R-2301.

Q. What does "current effective rates" mean?

A. "Current effective rates" includes the base rates resulting from HECO's 2005 test year rate case, plus the interim surcharge from HECO's test year 2007 rate case that is currently in effect.

On October 22, 2007, the Hawaii Public Utilities Commission ("Commission") issued Interim Decision and Order No. 23749 in Docket No. 2006-0386, HECO's test year 2007 rate case, authorizing an interim rate increase of $69,997,000 to produce annual revenues of $1,480,454,000. On June 20, 2008, the Commission approved HECO's request to modify the amount of the interim rate increase to $77,867,000 to produce annual revenue requirements of $1,480,538,000, and to reflect the lower revenue requirements approved concurrently by the Commission for HECO's test year 2005 rate case. See, Order Granting Hawaiian Electric, Inc.'s Motion to Adjust Interim Increase Filed on May 21, 2008, dated June 20, 2008, in Docket No. 2006-0386; and Order Approving Hawaiian Electric Company, Inc.'s Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008, dated June 20, 2008, in Docket No. 04-0113.

The $84,000 difference in the revenue requirement for the revised test year 2007 interim increase relative to the revenue requirement for the original test year 2007 interim increase results from implementation of the Commission's decision to adopt interest synchronization. The test year 2007 interim rate increase will be collected as a percentage of bill surcharge during the interim period from October 22, 2007, until the final decision and order is issued in Docket No. 2006-0386, HECO's test year 2007 rate case.

Q. Why are the Results of Operations reflected with, and without, informational advertising expenses?

A. The Results of Operations are reflected with, and without, informational advertising expenses, because the Parties could not reach an agreement on the appropriate level of test year informational advertising expenses, as discussed in greater detail by Mr. Alm in HECO RT-1 and Ms. Unemori in HECO RT-10A.

Q. Why are the Results of Operations reflected with returns on common equity of 11.00% and 11.25%?

A. The Results of Operations which reflect with an 11.00% return on common equity (HECO-R-2301 and HECO-R-2302) are based on Dr. Morin's proposed return on common equity, with Commission approval of the Revenue Adjustment Mechanism ("RAM") proposed by HECO in the decoupling proceeding, Docket No. 2008-0274, as discussed in greater detail by Mr. Alm in HECO RT-1 and Dr. Morin in HECO RT-19.

The Results of Operations which reflect with an 11.25% return on common equity (HECO-R-2303 and HECO-R-2304) are based on Dr. Morin's proposed return on common equity, assuming the Commission does not approve RAM proposed by HECO in the decoupling proceeding, Docket No. 2008-0274, as discussed in greater detail by Mr. Alm in HECO RT-1 and Dr. Morin in HECO RT-19.

Q. What revenue requirements are reflected in HECO's test year 2009 Results of Operations at 11.00% return on common equity, without informational advertising?

A. HECO's test year 2009 Results of Operations at 11.00% return on common equity, without informational advertising expenses included, reflects a revenue requirement of $1,382,305,000 (based on December 2008 fuel oil and purchased energy prices) to produce an 8.73% return on HECO's test year 2009 rate base of $1,252,828,000 at proposed rates, as shown in HECO-R-2302. At "current effective rates", HECO's test year 2009 Results of Operations without informational advertising expenses included, reflect total operating revenues of $1,296,374,000 (based on December 2008 fuel oil and purchased energy prices) for test year 2009, or $85,931,000 less than the test year 2009 revenue requirements at 11.00 % return on common equity, excluding informational advertising expenses, as shown in HECO-R-2302.

Q. What revenue requirements are reflected in HECO's test year 2009 Results of Operations at 11.25% return on common equity, with informational advertising?

A. HECO's test year 2009 Results of Operations at 11.25% return on common equity, with informational advertising expenses included, reflects a revenue requirement of $1,386,215,000 (based on December 2008 fuel oil and purchased energy prices) to produce an 8.87% return on HECO's test year 2009 rate base of $1,252,802,000 at proposed rates, as shown in HECO-R-2303. At "current effective rates", HECO's test year 2009 Results of Operations with informational advertising expenses included, reflect total operating revenues of $1,296,374,000 (based on December 2008 fuel oil and purchased energy prices) for test year 2009, or $89,841,000 less than the test year 2009 revenue requirements at 11.25 % return on common equity, including informational advertising expenses, as shown in HECO-R-2303.

Q. What revenue requirements are reflected in HECO's test year 2009 Results of Operations at 11.25% return on common equity, without informational advertising?

A. HECO's test year 2009 Results of Operations at 11.25% return on common equity, without informational advertising expenses included, reflects a revenue requirement of $1,385,365,000 (based on December 2008 fuel oil and purchased energy prices) to produce an 8.87% return on HECO's test year 2009 rate base of $1,252,800,000 at proposed rates, as shown in HECO-R-2304. At "current effective rates", HECO's test year 2009 Results of Operations with informational advertising expenses included, reflect total operating revenues of $1,296,374,000 (based on December 2008 fuel oil and purchased energy prices) for test year 2009, or $88,991,000 less than the test year 2009 revenue requirements at 11.25 % return on common equity, excluding informational advertising expenses, as shown in HECO-R-2304.

Q. What revenue increase does HECO propose for the Interim Increase?

A. For the Interim Increase, HECO proposes an interim rate increase of 79,811,000, based on test year 2009 revenue requirements of $1,376,185,000 and revenues at current effective rates of $1,296,374 (based on December 2008 fuel oil and purchased energy prices), as reflected in HECO's Statement of Probable Entitlement filed with the Commission on May 18, 2009.

Q. Are Demand-Side Management ("DSM") costs included in the Company's test year revenue requirements?

A. Only DSM costs that are currently being recovered in base rates are included in the Company's test year revenue requirements. Incremental DSM program costs have been removed from the test year. For the purposes of this proceeding, the Company is using the method of cost recovery that is currently in place by which DSM program costs currently being recovered in base rates continue to be recovered in base rates and incremental DSM program costs currently recovered through the DSM surcharge continue to be recovered through that surcharge. Mr. Hee provided a detailed discussion of the treatment of DSM program costs in test year 2009 in HECO T-10.

Q. What would HECO's test year 2009 return on rate base be for ratemaking purposes without rate relief?

A. Without rate relief, HECO's normalized test year 2009 Results of Operation, with informational advertising expenses included, indicate a rate of return on rate base of 4.87% based on revenues at current effective rates, as shown in HECO-R-2301.

Q. How much additional operating income will HECO's proposed rates and charges produce?

A. The proposed revenue increase at 11.00% return on common equity, including informational advertising expenses, over current effective rates will increase HECO's estimated test year 2009 operating income by $38,474,000 to produce an 8.73% return on the test year 2009 rate base of $1,252,830,000 at proposed rates, as shown on HECO-R-2301.

Q. How much of the additional revenues will go towards paying increased taxes?

A. Approximately 44% of the requested increase in revenues at 11.00% return on common equity, including informational advertising expenses, ($38,474,000 of the proposed $86,779,000 increase over current effective rates) will be used to pay increased county, state and federal taxes, as shown on HECO-R-2301.

RATE INCREASE IMPLEMENTATION

Q. How does HECO propose to implement its proposed rate increase?

A. HECO proposes to implement the proposed rate increase in two steps:

1) Interim Increase, and
2) Final Increase.

Q. When *does* HECO *request that the proposed* Interim *Increase be made effective?*

A. HECO requests that it be allowed to implement its proposed Interim Increase as soon as practicable. HECO filed its Statement of Probable Entitlement on May 18, 2009, pursuant to the Commission's Order Amending Stipulated Procedural Order filed January 21, 2009.

Q. How does HECO plan to allocate the interim rate increase to the different customer classes of service?

A. HECO plans to allocate the interim increase in electric revenues to customer classes of service in the percentages shown in the section on Cost of Service/Rate Increase Allocation/Rate Design in Exhibit 1 of the Stipulated Settlement Letter:

Schedule R	35.74%
Schedule G	4.37%
Schedule J	33.86%
Schedule H	0.55%
Schedule PS	8.64%
Schedule PP	15.17%

Schedule PT 1.03%

Schedule F 0.64%

According to the Stipulated Settlement Letter, this considers the positions of HECO, the Division of Consumer Advocacy ("Consumer Advocate"), and the Department of Defense ("DOD") on cost of service and movement of inter-class revenues towards the respective cost of service positions. In addition, the interim increase in electric revenues will be assigned to Schedule PP customers such that the Schedule PP customers who are directly served from a substation are assigned a revenue increase that is 50% of the overall revenue percentage increase that the interim increase represents. Finally, the interim rate increase will be implemented on a cents per kWh basis. This interim rate increase implementation is in accordance with the Parties' Stipulated Settlement Letter filed with the Commission on May 15, 2009, pages 84-85; and HECO's Statement of Probable Entitlement filed with the Commission on May 18, 2009, page 10.

Q. What rate design changes does HECO plan to implement when it implements the Interim Increase?

A. HECO plans to implement its RBA decoupling mechanism tariff provision with the Interim Increase, subject to Commission approval. The RBA tariff provision is included in the Stipulated Settlement Letter, dated May 15, 2009, at HECO T-22, Attachment 1, pages 1-3. HECO does not plan to implement any other rate design changes when it implements the Interim Increase.

Q. Why does HECO need an interim increase as soon as practicable?

A. Interim rate relief at this time is essential. Under the average test year concept followed in reaching the settlement agreement with the Consumer Advocate and the DOD, the agreed upon increase in revenues is the amount needed at the beginning of the test year to provide a reasonable opportunity to earn the fair rate of return of the test year. The later in the test year that the increase is received, the lower will be the amount of the increase actually received in the test year. In simple terms, if an annual increase of $80 million is awarded after one-half of the 2009 test year has passed (which is the earliest that the interim increase could be made effective), then only approximately one-half of the increase (or $40 million) will actually be received in 2009. HECO's test year 2009 Results of Operations show that HECO had a need for a rate increase at the beginning of 2009. Without rate relief, HECO's will earn a 4.87% return on its rate base, as shown in HECO-R-2301. Therefore, HECO requires the requested increase as soon as practicable to provide the Company an opportunity to earn the rate of return on rate base authorized by the Commission in this proceeding.

Q. When does HECO propose to make the Final Increase effective?

A. The Final Increase will become effective when the final decision and order in this docket is issued by the Commission. The amount of the Final Increase will provide for the amount of the total revenue increase authorized by the Commission's final decision and order, adjusted for the Interim Increase.

Q. What rate design does HECO propose to use to implement the Final Increase?

A. HECO plans to implement the final rate increase by allocating the increase in electric revenues to customer classes of service in the percentages shown in the section on Cost of Service/Rate Increase Allocation/Rate Design in Exhibit 1 of the Stipulated Settlement Letter:

Schedule R	35.74%
Schedule G	4.48%
Schedule J	34.22%

Schedule DS	7.06%
Schedule P	17.86%
Schedule F	0.64%

According to the Stipulated Settlement Letter, this considers the positions of HECO, the Consumer Advocate, and the DOD on cost of service and movement of inter-class revenues towards the respective cost of service positions. See Exhibit 1 of the Stipulated Settlement Letter, dated May 15, 2009, page 85; Statement of Probable Entitlement, dated May 18, 2009, page 10.

In addition, HECO requests the Commission to approve the Purchased Power Adjustment Clause tariff (provided in Attachment 1 of the HECO T-22 Rate Case Update, pages 37-39), to be effective on the same effective date as the final rates and charges approved in this proceeding.

SUMMARY

Q. Ms. Sekimura, do you have any concluding remarks?

A. Yes. HECO has presented substantial evidence in its 23 written direct testimonies (with exhibits and workpapers) sponsored by 22 different witnesses, and six written rebuttal testimonies (with exhibits and workpapers) sponsored by five different witnesses, to support HECO's requested rate increase. HECO's Results of Operations, with approval of our proposed RAM decoupling mechanism and informational advertising expenses, and at an 11.00% return on common equity for test year 2009 indicates that a rate increase of $86,779,000 over revenues at current effective rates is necessary to provide HECO with an opportunity to earn a rate of return of 8.73% on its rate base of $1,252,830,000 at proposed rates.

Adequate and timely rate relief will allow HECO to maintain its financial integrity and its ability to attract capital for its capital expenditures. Thus, it is essential that the proceeding in this docket progress as expeditiously as possible. HECO respectfully requests that the Commission grant:

1) An Interim Increase of $79,811,000 as soon as practicable, pursuant to Section 269-16(d), Hawaii Revised Statutes, as well as approval of HECO's Revenue Balancing Account tariff provision, and

2) A Final Increase of $86,779,000 over current effective rates for test year 2009, as well as approval of the proposed revisions to HECO's rate schedules and rules.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.
Rebuttal at 11% at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.73% Return on Average Rate Base
Electric Sales Revenue	1,291,619	86,651	1,378,270
Other Operating Revenue	4,140	128	4,268
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	86,779	1,383,153
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	6,558		6,558
Administration & General	88,948		88,948
Operation and Maintenance	1,016,799	0	1,016,799
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,707	129,810
Interest on Customer Deposits	479		479
Income Taxes	15,511	30,767	46,278
TOTAL OPERATING EXPENSES	1,235,307	38,474	1,273,781
OPERATING INCOME	61,067	48,305	109,372
AVERAGE RATE BASE	1,253,611	(781)	1,252,830
RATE OF RETURN ON AVERAGE RATE BASE	4.87%		8.73%

Hawaiian Electric Company, Inc.
Rebuttal at 11% w/o Advertising at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.73% Return on Average Rate Base
Electric Sales Revenue	1,291,619	85,804	1,377,423
Other Operating Revenue	4,140	127	4,267
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	85,931	1,382,305
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	5,784		5,784
Administration & General	88,948		88,948
Operation and Maintenance	1,016,025	0	1,016,025
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,632	129,735
Interest on Customer Deposits	479		479
Income Taxes	15,813	30,466	46,279
TOTAL OPERATING EXPENSES	1,234,835	38,098	1,272,933
OPERATING INCOME	61,539	47,833	109,372
AVERAGE RATE BASE	1,253,601	(773)	1,252,828
RATE OF RETURN ON AVERAGE RATE BASE	4.91%		8.73%

Hawaiian Electric Company, Inc.
Rebuttal at 11.25% at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.87% Return on Average Rate Base
Electric Sales Revenue	1,291,619	89,711	1,381,330
Other Operating Revenue	4,140	130	4,270
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	89,841	1,386,215
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	6,558		6,558
Administration & General	88,948		88,948
Operation and Maintenance	1,016,799	0	1,016,799
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,979	130,082
Interest on Customer Deposits	479		479
Income Taxes	15,463	31,852	47,315
TOTAL OPERATING EXPENSES	1,235,259	39,831	1,275,090
OPERATING INCOME	61,115	50,010	111,125
AVERAGE RATE BASE	1,253,611	(809)	1,252,802
RATE OF RETURN ON AVERAGE RATE BASE	4.88%		8.87%

Hawaiian Electric Company, Inc.
Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.87% Return on Average Rate Base
Electric Sales Revenue	1,291,619	88,861	1,380,480
Other Operating Revenue	4,140	130	4,270
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	88,991	1,385,365
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	5,784		5,784
Administration & General	88,948		88,948
Operation and Maintenance	1,016,025	0	1,016,025
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,904	130,007
Interest on Customer Deposits	479		479
Income Taxes	15,765	31,551	47,316
TOTAL OPERATING EXPENSES	1,234,787	39,455	1,274,242
OPERATING INCOME	61,587	49,536	111,123
AVERAGE RATE BASE	1,253,601	(801)	1,252,800
RATE OF RETURN ON AVERAGE RATE BASE	4.91%		8.87%

Hawaiian Electric Company, Inc.
Rebuttal at 11% at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.73% Return on Average Rate Base
Electric Sales Revenue	1,291,619	86,651	1,378,270
Other Operating Revenue	4,140	128	4,268
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	86,779	1,383,153
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	6,558		6,558
Administration & General	88,948		88,948
Operation and Maintenance	1,016,799	0	1,016,799
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,707	129,810
Interest on Customer Deposits	479		479
Income Taxes	15,511	30,767	46,278
TOTAL OPERATING EXPENSES	1,235,307	38,474	1,273,781
OPERATING INCOME	61,067	48,305	109,372
AVERAGE RATE BASE	1,253,611	(781)	1,252,830
RATE OF RETURN ON AVERAGE RATE BASE	4.87%		8.73%

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	0	0	0.75%	0.000%
Long-Term Debt	576,569	40.76	5.81%	2.368%
Hybrid Securities	27,775	1.96	7.41%	0.146%
Preferred Stock	20,696	1.46	5.48%	0.080%
Common Equity	789,374	55.81	11.00%	6.139%
Total	1,414,414	100.00		
Estimated Composite Cost of Capital				8.733%
			or	8.73%

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
2009 AVERAGE RATE BASE
($ Thousands)

	Beginning Balance	End of Year Balance	Average Balance
Investments in Assets Serving Customers			
Net Cost of Plant in Service	1,365,578	1,575,485	1,470,532
Property Held for Future Use	2,331	2,331	2,331
Fuel Inventory	43,274	46,736	45,005
Materials & Supplies Inventories	16,391	16,015	16,203
Unamort. Net SFAS 109 Reg. Asset	57,753	62,718	60,236
Unamort Sys Dev Costs	4,684	7,936	6,310
RO Pipeline Reg Asset	0	6,366	3,183
ARO Reg Asset	10	12	11
Total Investments in Assets	1,490,021	1,717,599	1,603,811
Funds From Non-Investors			
Unamortized CIAC	178,757	183,375	181,066
Customer Advances	947	807	877
Customer Deposits	8,201	8,581	8,391
Accumulated Def. Income Taxes	132,510	156,551	144,531
Unamort State ITC (Gross)	30,102	28,650	29,376
Unamortized Gain on Sale	1,345	746	1,046
Pension Reg Liability	3,051	-3,454	-202
OPEB Reg Liability	777	433	605
Total Deductions	355,690	375,689	365,690
Difference			1,238,121
Working Cash at Current Effective Rates			15,490
Rate Base at Current Effective Rates			1,253,611
Change in Rate Base - Working Cash			(781)
Rate Base at Proposed Rates			1,252,830

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	431,206
O&M Labor	37	11	26	99,620
O&M Nonlabor	37	33	4	123,124
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	114,909
Income Taxes-Curr Eff Rates	37	39	(2)	(8,530)
Income Taxes-Proposed Rates	37	39	(2)	22,237
Purchased Power	37	37	0	346,467

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	1,181	23,628	1,181	23,628
O&M Labor	273	7,096	273	7,096
O&M Nonlabor	337	1,349	337	1,349
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	949	0	949	0
Revenue Taxes	315	(9,130)	336	(9,742)
Income Taxes-Curr Eff Rates	(23)	47		
Income Taxes-Proposed Rates	61	-	61	(122)
Settlement Adjustment		(7,500)		(7,500)
Total		15,490		14,709
Change in Working Cash				(781)

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,296,374	86,779	1,383,153
Operating Expenses:			
Fuel Oil and Purchased Power	784,815		784,815
Other Operation & Maintenance Expense	231,984	0	231,984
Depreciation	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	122,103	7,707	129,810
Interest on Customer Deposits	479		479
Total Operating Expenses	1,219,796	7,707	1,227,503
Operating Income Before Income Taxes	76,578	79,072	155,650
Tax Adjustments:			
Interest Expense	(31,496)		(31,496)
Meals and Entertainment	78		78
	(31,418)	0	(31,418)
Taxable Income at Ordinary Rates	45,160	79,072	124,232
Income Tax Exp at Ordinary Rates	17,572	30,767	48,339
Tax Benefit of Domestic Production Activities Deduction	1,823		1,823
Tax Effect of Deductible Preferred Stock Dividends	23		23
R&D Credit	215		215
TOTAL INCOME TAX EXPENSE	15,511	30,767	46,278

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,291,619	86,651	1,378,270
Other Operating Revenue		4,140	128	4,268
Operating Revenues		1,295,759	86,779	1,382,538
Public Service Tax	5.885%	76,179	5,107	81,286
PUC Fees	0.500%	6,472	434	6,906
Franchise Tax	2.500%	32,258	2,166	34,424
Payroll Tax		7,194		7,194
TOTAL TAXES OTHER THAN INCOME TAX		122,103	7,707	129,810

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,296,374
Fuel and Purchased Power Expenses		784,815
Other O&M Expenses		231,984
Depreciation & Amortization Expense		81,868
Amortization of State ITC		(1,453)
Taxes Other than Income		122,103
Interest on Customer Deposits		479
Income Taxes		15,511
Total Operating Expenses		1,235,307
OPERATING INCOME AT CURRENT EFFECTIVE RATES		61,067
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,252,830
Proposed Rate of Return on Rate Base	x	8.73%
Operating Income		109,372
Less: Operating Income at Current Effective Rate		61,067
INCREASE IN OPERATING INCOME		48,305
OPERATING REVENUES:		
Increase in Operating Income		48,305
Operating Income Divisor	(divided by)	0.55665
INCREASE IN OPERATING REVENUES		86,779
Increase in Electric Sales Revenue		86,651
Other Operating Revenue Rate	x	0.148%
Increase in Other Operating Revenues		128
		86,779

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		86,651
Bad Debt Rate	x	0.0000
INCREASE IN BAD DEBT EXPENSE		0
REVENUE TAX:		
Increase in Operating Revenues		86,779
Less: Increase in Bad Debt Expense		0
		86,779
PSC Tax & PUC Fees Rate	x	6.385%
		5,541
Increase in Electric Revenues		86,651
Less: Increase in Bad Debt Expense		0
		86,651
Franchise Tax Rate	x	2.500%
		2,166
INCREASE IN REVENUE TAX		7,707
INCOME TAX:		
Increase in Operating Revenues		86,779
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.454%
INCREASE IN INCOME TAX		30,767
INCREASE IN OPERATING INCOME (check)		48,305

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	7,707	21	(29)	(612)
Income Tax at curr eff rate	(8,530)	(23)	(2)	(47)
Income Tax at proposed rate	22,237	61	(2)	(122)
CHANGE IN RATE BASE - WORKING CASH				(781)
Rate Base at Current Effective Rates				1,253,611
PROPOSED RATE BASE				1,252,830
Operating Income at Current Effective Rates				61,067
Increase in Operating Income				48,305
OPERATING INCOME AT PROPOSED RATES				109,372
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.73%

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
SUPPORT WORKSHEET
2009

OPERATING REVENUES:	
Electric Sales Revenues	1,291,619
Other Operating Revenues	4,140
Gain on Sale of Land	615
TOTAL OPERATING REVENUES	1,296,374
FUEL OIL AND PURCHASE POWER EXPENSES:	
Fuel Oil Expense	431,206
Fuel Related Non-labor Exp	6,549
Fuel Handling Labor Expense	593
Fuel Oil Expense	438,348
Purchased Power Expense	346,467
TOTAL FUEL OIL AND PURCHASE POWER EXPENSES	784,815
OTHER OPERATION & MAINTENANCE EXPENSES:	
Production	78,973
Transmission	13,859
Distribution	29,844
Customer Account	12,500
Allowance for Uncollectible Accounts	1,302
Customer Service	6,558
Administration & General	88,948
TOTAL OTHER OPERATION & MAINTENANCE EXPENSES	231,984

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
SUPPORT WORKSHEET
2009

TOTAL FUEL OIL & PP AND OTH O&M EXPENSES (LABOR/NONLABOR)		
Fuel Oil Expense		431,206
Purchase Power Expense		346,467
Total Labor Expense		
Labor Expense		99,620
Total Labor Expense		99,620
Total Nonlabor Expense		
Nonlabor Expense		132,957
Fuel Related Expense		6,549
Payroll Taxes		7,194
Bad Debt Expense		(1,302)
Pension Expense & Amortization		(22,274)
		123,124
TOTAL FUEL OIL & PP, OTH O&M AND PR TAX EXPENSES		1,000,417
REVENUE TAX		
Public Service Tax		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
Public Service Tax Rate	x	5.885%
Total PSC Tax		76,179
PUC Fees		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
PUC Tax Rate	x	0.500%
Total PUC Tax		6,472

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
SUPPORT WORKSHEET
2009

Franchise Tax		
Electric Sales Revenues		1,291,619
Less: Bad Debt Expense		(1,302)
		1,290,317
Franchise Tax Rate	x	2.500%
Total Franchise Tax		32,258
TOTAL REVENUE TAX		114,909
INTEREST EXPENSE:		
Weighted Cost of Debt		
Short-Term Debt		0.000%
Long-Term Debt		2.368%
Hybrid Securities		0.146%
Total		2.514%
Rate Base at Proposed Rates	x	1,252,830
TOTAL INTEREST EXPENSE		31,496
INCOME TAX EXPENSE SUMMARY		
Current		(8,530)
Deferred		24,041
State ITC		0
TOTAL INCOME TAX EXPENSE		15,511
CALCULATIONS OF REVENUE TAX RATE:		
Franchise Tax Rate adjusted for Change in Oth Oper Revenues and Bad Debt		0.02496
PSC Tax Rate adjusted for Bad Debt		0.05885
PUC Tax Rate adjusted for Bad Debt		0.00500
REVENUE TAX RATE		0.08881
CALCULATIONS OF COMPOSITE INCOME TAX RATE:		
State Tax Rate		0.06015
Federal Tax Rate		0.35000
State Tax Rate		0.06015
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Tax		(0.02105)
COMPOSITE INCOME TAX RATE		0.38910

Hawaiian Electric Company, Inc.

Rebuttal at 11% at Curr Eff Rates
SUPPORT WORKSHEET
2009

CALCULATIONS OF COMPOSITE CAPITAL GAINS TAX RATE:		
State Capital Gains Tax Rate		0.03759
Federal Tax Rate		0.35000
State Capital Gains Tax Rate		0.03759
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Capital Gains Tax Rate		(0.01316)
COMPOSITE CAPITAL GAINS TAX RATE		0.37444
CALCULATIONS OF EFFECTIVE INCOME TAX RATE:		
PSC Tax & PUC Fees Rates adjusted for Bad Debt		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev and Bad Debt		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Revenue Tax and Bad Debt rate		0.08881
Rev Tax & Bad Debt Reciprocal (1 - 0.08881)		0.91119
Composite Income Tax Rate	x	0.38910
EFFECTIVE INCOME TAX RATE AFTER CONSIDERING REVENUE TAX & BAD DEBT		0.35454
CALCULATIONS OF OPERATING INCOME DIVISOR:		
PSC Tax & PUC Fees Rates		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Effective Income Tax Rate after considering revenue tax & bad debt		0.35454
		0.44335
OPERATING INCOME DIVISOR (1 - 0.44335)		0.55665

Hawaiian Electric Company, Inc.
Rebuttal at 11% w/o Advertising at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.73% Return on Average Rate Base
Electric Sales Revenue	1,291,619	85,804	1,377,423
Other Operating Revenue	4,140	127	4,267
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	85,931	1,382,305
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	5,784		5,784
Administration & General	88,948		88,948
Operation and Maintenance	1,016,025	0	1,016,025
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,632	129,735
Interest on Customer Deposits	479		479
Income Taxes	15,813	30,466	46,279
TOTAL OPERATING EXPENSES	1,234,835	38,098	1,272,933
OPERATING INCOME	61,539	47,833	109,372
AVERAGE RATE BASE	1,253,601	(773)	1,252,828
RATE OF RETURN ON AVERAGE RATE BASE	4.91%		8.73%

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	0	0	0.75%	0.000%
Long-Term Debt	576,569	40.76	5.81%	2.368%
Hybrid Securities	27,775	1.96	7.41%	0.146%
Preferred Stock	20,696	1.46	5.48%	0.080%
Common Equity	789,374	55.81	11.00%	6.139%
Total	1,414,414	100.00		
Estimated Composite Cost of Capital				8.733%
			or	8.73%

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
2009 AVERAGE RATE BASE
($ Thousands)

	Beginning Balance	End of Year Balance	Average Balance
Investments in Assets Serving Customers			
Net Cost of Plant in Service	1,365,578	1,575,485	1,470,532
Property Held for Future Use	2,331	2,331	2,331
Fuel Inventory	43,274	46,736	45,005
Materials & Supplies Inventories	16,391	16,015	16,203
Unamort. Net SFAS 109 Reg. Asset	57,753	62,718	60,236
Unamort Sys Dev Costs	4,684	7,936	6,310
RO Pipeline Reg Asset	0	6,366	3,183
ARO Reg Asset	10	12	11
Total Investments in Assets	1,490,021	1,717,599	1,603,811
Funds From Non-Investors			
Unamortized CIAC	178,757	183,375	181,066
Customer Advances	947	807	877
Customer Deposits	8,201	8,581	8,391
Accumulated Def. Income Taxes	132,510	156,551	144,531
Unamort State ITC (Gross)	30,102	28,650	29,376
Unamortized Gain on Sale	1,345	746	1,046
Pension Reg Liability	3,051	-3,454	-202
OPEB Reg Liability	777	433	605
Total Deductions	355,690	375,689	365,690
Difference			1,238,121
Working Cash at Current Effective Rates			15,480
Rate Base at Current Effective Rates			1,253,601
Change in Rate Base - Working Cash			(773)
Rate Base at Proposed Rates			1,252,828

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	431,206
O&M Labor	37	11	26	99,620
O&M Nonlabor	37	33	4	122,350
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	114,909
Income Taxes-Curr Eff Rates	37	39	(2)	(8,228)
Income Taxes-Proposed Rates	37	39	(2)	22,238
Purchased Power	37	37	0	346,467

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	1,181	23,628	1,181	23,628
O&M Labor	273	7,096	273	7,096
O&M Nonlabor	335	1,341	335	1,341
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	949	0	949	0
Revenue Taxes	315	(9,130)	336	(9,736)
Income Taxes-Curr Eff Rates	(23)	45		
Income Taxes-Proposed Rates	61	-	61	(122)
Settlement Adjustment		(7,500)		(7,500)
Total		15,480		14,707
Change in Working Cash				(773)

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,296,374	85,931	1,382,305
Operating Expenses:			
Fuel Oil and Purchased Power	784,815		784,815
Other Operation & Maintenance Expense	231,210	0	231,210
Depreciation	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	122,103	7,632	129,735
Interest on Customer Deposits	479		479
Total Operating Expenses	1,219,022	7,632	1,226,654
Operating Income Before Income Taxes	77,352	78,299	155,651
Tax Adjustments:			
Interest Expense	(31,496)		(31,496)
Meals and Entertainment	78		78
	(31,418)	0	(31,418)
Taxable Income at Ordinary Rates	45,934	78,299	124,233
Income Tax Exp at Ordinary Rates	17,873	30,466	48,339
Tax Benefit of Domestic Production Activities Deduction	1,822		1,822
Tax Effect of Deductible Preferred Stock Dividends	23		23
R&D Credit	215		215
TOTAL INCOME TAX EXPENSE	15,813	30,466	46,279

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,291,619	85,804	1,377,423
Other Operating Revenue		4,140	127	4,267
Operating Revenues		1,295,759	85,931	1,381,690
Public Service Tax	5.885%	76,179	5,057	81,236
PUC Fees	0.500%	6,472	430	6,902
Franchise Tax	2.500%	32,258	2,145	34,403
Payroll Tax		7,194		7,194
TOTAL TAXES OTHER THAN INCOME TAX		122,103	7,632	129,735

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,296,374
Fuel and Purchased Power Expenses		784,815
Other O&M Expenses		231,210
Depreciation & Amortization Expense		81,868
Amortization of State ITC		(1,453)
Taxes Other than Income		122,103
Interest on Customer Deposits		479
Income Taxes		15,813
Total Operating Expenses		1,234,835
OPERATING INCOME AT CURRENT EFFECTIVE RATES		61,539
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,252,828
Proposed Rate of Return on Rate Base	x	8.73%
Operating Income		109,372
Less: Operating Income at Current Effective Rate		61,539
INCREASE IN OPERATING INCOME		47,833
OPERATING REVENUES:		
Increase in Operating Income		47,833
Operating Income Divisor	(divided by)	0.55665
INCREASE IN OPERATING REVENUES		85,931
Increase in Electric Sales Revenue		85,804
Other Operating Revenue Rate	x	0.148%
Increase in Other Operating Revenues		127
		85,931

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		85,804
Bad Debt Rate	x	0.0000
INCREASE IN BAD DEBT EXPENSE		0
REVENUE TAX:		
Increase in Operating Revenues		85,931
Less: Increase in Bad Debt Expense		0
		85,931
PSC Tax & PUC Fees Rate	x	6.385%
		5,487
Increase in Electric Revenues		85,804
Less: Increase in Bad Debt Expense		0
		85,804
Franchise Tax Rate	x	2.500%
		2,145
INCREASE IN REVENUE TAX		7,632
INCOME TAX:		
Increase in Operating Revenues		85,931
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.454%
INCREASE IN INCOME TAX		30,466
INCREASE IN OPERATING INCOME (check)		47,833

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	7,632	21	(29)	(606)
Income Tax at curr eff rate	(8,228)	(23)	(2)	(45)
Income Tax at proposed rate	22,238	61	(2)	(122)
CHANGE IN RATE BASE - WORKING CASH				(773)
Rate Base at Current Effective Rates				1,253,601
PROPOSED RATE BASE				1,252,828
Operating Income at Current Effective Rates				61,539
Increase in Operating Income				47,833
OPERATING INCOME AT PROPOSED RATES				109,372
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.73%

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

OPERATING REVENUES:	
Electric Sales Revenues	1,291,619
Other Operating Revenues	4,140
Gain on Sale of Land	615
TOTAL OPERATING REVENUES	1,296,374
FUEL OIL AND PURCHASE POWER EXPENSES:	
Fuel Oil Expense	431,206
Fuel Related Non-labor Exp	6,549
Fuel Handling Labor Expense	593
Fuel Oil Expense	438,348
Purchased Power Expense	346,467
TOTAL FUEL OIL AND PURCHASE POWER EXPENSES	784,815
OTHER OPERATION & MAINTENANCE EXPENSES:	
Production	78,973
Transmission	13,859
Distribution	29,844
Customer Account	12,500
Allowance for Uncollectible Accounts	1,302
Customer Service	5,784
Administration & General	88,948
TOTAL OTHER OPERATION & MAINTENANCE EXPENSES	231,210

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

TOTAL FUEL OIL & PP AND OTH O&M EXPENSES (LABOR/NONLABOR)		
Fuel Oil Expense		431,206
Purchase Power Expense		346,467
Total Labor Expense		
Labor Expense		99,620
Total Labor Expense		99,620
Total Nonlabor Expense		
Nonlabor Expense		132,183
Fuel Related Expense		6,549
Payroll Taxes		7,194
Bad Debt Expense		(1,302)
Pension Expense & Amortization		(22,274)
		122,350
TOTAL FUEL OIL & PP, OTH O&M AND PR TAX EXPENSES		999,643
REVENUE TAX		
Public Service Tax		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
Public Service Tax Rate	x	5.885%
Total PSC Tax		76,179
PUC Fees		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
PUC Tax Rate	x	0.500%
Total PUC Tax		6,472

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

Franchise Tax		
Electric Sales Revenues		1,291,619
Less: Bad Debt Expense		(1,302)
		1,290,317
Franchise Tax Rate	x	2.500%
Total Franchise Tax		32,258
TOTAL REVENUE TAX		114,909
INTEREST EXPENSE:		
Weighted Cost of Debt		
Short-Term Debt		0.000%
Long-Term Debt		2.368%
Hybrid Securities		0.146%
Total		2.514%
Rate Base at Proposed Rates	x	1,252,828
TOTAL INTEREST EXPENSE		31,496
INCOME TAX EXPENSE SUMMARY		
Current		(8,228)
Deferred		24,041
State ITC		0
TOTAL INCOME TAX EXPENSE		15,813
CALCULATIONS OF REVENUE TAX RATE:		
Franchise Tax Rate adjusted for Change in Oth Oper Revenues and Bad Debt		0.02496
PSC Tax Rate adjusted for Bad Debt		0.05885
PUC Tax Rate adjusted for Bad Debt		0.00500
REVENUE TAX RATE		0.08881
CALCULATIONS OF COMPOSITE INCOME TAX RATE:		
State Tax Rate		0.06015
Federal Tax Rate		0.35000
State Tax Rate		0.06015
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Tax		(0.02105)
COMPOSITE INCOME TAX RATE		0.38910

Hawaiian Electric Company, Inc.

Rebuttal at 11% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

CALCULATIONS OF COMPOSITE CAPITAL GAINS TAX RATE:		
State Capital Gains Tax Rate		0.03759
Federal Tax Rate		0.35000
State Capital Gains Tax Rate		0.03759
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Capital Gains Tax Rate		(0.01316)
COMPOSITE CAPITAL GAINS TAX RATE		0.37444
CALCULATIONS OF EFFECTIVE INCOME TAX RATE:		
PSC Tax & PUC Fees Rates adjusted for Bad Debt		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev and Bad Debt		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Revenue Tax and Bad Debt rate		0.08881
Rev Tax & Bad Debt Reciprocal (1 - 0.08881)		0.91119
Composite Income Tax Rate	x	0.38910
EFFECTIVE INCOME TAX RATE AFTER CONSIDERING REVENUE TAX & BAD DEBT		0.35454
CALCULATIONS OF OPERATING INCOME DIVISOR:		
PSC Tax & PUC Fees Rates		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Effective Income Tax Rate after considering revenue tax & bad debt		0.35454
		0.44335
OPERATING INCOME DIVISOR (1 - 0.44335)		0.55665

Hawaiian Electric Company, Inc.
Rebuttal at 11.25% at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.87% Return on Average Rate Base
Electric Sales Revenue	1,291,619	89,711	1,381,330
Other Operating Revenue	4,140	130	4,270
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	89,841	1,386,215
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	6,558		6,558
Administration & General	88,948		88,948
Operation and Maintenance	1,016,799	0	1,016,799
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,979	130,082
Interest on Customer Deposits	479		479
Income Taxes	15,463	31,852	47,315
TOTAL OPERATING EXPENSES	1,235,259	39,831	1,275,090
OPERATING INCOME	61,115	50,010	111,125
AVERAGE RATE BASE	1,253,611	(809)	1,252,802
RATE OF RETURN ON AVERAGE RATE BASE	4.88%		8.87%

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	0	0	0.75%	0.000%
Long-Term Debt	576,569	40.76	5.81%	2.368%
Hybrid Securities	27,775	1.96	7.41%	0.146%
Preferred Stock	20,696	1.46	5.48%	0.080%
Common Equity	789,374	55.81	11.25%	6.279%
Total	1,414,414	100.00		
Estimated Composite Cost of Capital				8.873%
			or	8.87%

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
2009 AVERAGE RATE BASE
($ Thousands)

	Beginning Balance	End of Year Balance	Average Balance
Investments in Assets Serving Customers			
Net Cost of Plant in Service	1,365,578	1,575,485	1,470,532
Property Held for Future Use	2,331	2,331	2,331
Fuel Inventory	43,274	46,736	45,005
Materials & Supplies Inventories	16,391	16,015	16,203
Unamort. Net SFAS 109 Reg. Asset	57,753	62,718	60,236
Unamort Sys Dev Costs	4,684	7,936	6,310
RO Pipeline Reg Asset	0	6,366	3,183
ARO Reg Asset	10	12	11
Total Investments in Assets	1,490,021	1,717,599	1,603,811
Funds From Non-Investors			
Unamortized CIAC	178,757	183,375	181,066
Customer Advances	947	807	877
Customer Deposits	8,201	8,581	8,391
Accumulated Def. Income Taxes	132,510	156,551	144,531
Unamort State ITC (Gross)	30,102	28,650	29,376
Unamortized Gain on Sale	1,345	746	1,046
Pension Reg Liability	3,051	-3,454	-202
OPEB Reg Liability	777	433	605
Total Deductions	355,690	375,689	365,690
Difference			1,238,121
Working Cash at Current Effective Rates			15,490
Rate Base at Current Effective Rates			1,253,611
Change in Rate Base - Working Cash			(809)
Rate Base at Proposed Rates			1,252,802

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	431,206
O&M Labor	37	11	26	99,620
O&M Nonlabor	37	33	4	123,124
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	114,909
Income Taxes-Curr Eff Rates	37	39	(2)	(8,578)
Income Taxes-Proposed Rates	37	39	(2)	23,274
Purchased Power	37	37	0	346,467

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	1,181	23,628	1,181	23,628
O&M Labor	273	7,096	273	7,096
O&M Nonlabor	337	1,349	337	1,349
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	949	0	949	0
Revenue Taxes	315	(9,130)	337	(9,764)
Income Taxes-Curr Eff Rates	(24)	47		
Income Taxes-Proposed Rates	64	-	64	(128)
Settlement Adjustment		(7,500)		(7,500)
Total		15,490		14,681
Change in Working Cash				(809)

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,296,374	89,841	1,386,215
Operating Expenses:			
Fuel Oil and Purchased Power	784,815		784,815
Other Operation & Maintenance Expense	231,984	0	231,984
Depreciation	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	122,103	7,979	130,082
Interest on Customer Deposits	479		479
Total Operating Expenses	1,219,796	7,979	1,227,775
Operating Income Before Income Taxes	76,578	81,862	158,440
Tax Adjustments:			
Interest Expense	(31,495)		(31,495)
Meals and Entertainment	78		78
	(31,417)	0	(31,417)
Taxable Income at Ordinary Rates	45,161	81,862	127,023
Income Tax Exp at Ordinary Rates	17,572	31,852	49,424
Tax Benefit of Domestic Production Activities Deduction	1,871		1,871
Tax Effect of Deductible Preferred Stock Dividends	23		23
R&D Credit	215		215
TOTAL INCOME TAX EXPENSE	15,463	31,852	47,315

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,291,619	89,711	1,381,330
Other Operating Revenue		4,140	130	4,270
Operating Revenues		1,295,759	89,841	1,385,600
Public Service Tax	5.885%	76,179	5,287	81,466
PUC Fees	0.500%	6,472	449	6,921
Franchise Tax	2.500%	32,258	2,243	34,501
Payroll Tax		7,194		7,194
TOTAL TAXES OTHER THAN INCOME TAX		122,103	7,979	130,082

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,296,374
Fuel and Purchased Power Expenses		784,815
Other O&M Expenses		231,984
Depreciation & Amortization Expense		81,868
Amortization of State ITC		(1,453)
Taxes Other than Income		122,103
Interest on Customer Deposits		479
Income Taxes		15,463
Total Operating Expenses		1,235,259
OPERATING INCOME AT CURRENT EFFECTIVE RATES		61,115
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,252,802
Proposed Rate of Return on Rate Base	x	8.87%
Operating Income		111,124
Less: Operating Income at Current Effective Rate		61,115
INCREASE IN OPERATING INCOME		50,009
OPERATING REVENUES:		
Increase in Operating Income		50,009
Operating Income Divisor	(divided by)	0.55665
INCREASE IN OPERATING REVENUES		89,841
Increase in Electric Sales Revenue		89,711
Other Operating Revenue Rate	x	0.145%
Increase in Other Operating Revenues		130
		89,841

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		89,711
Bad Debt Rate	x	0.0000
INCREASE IN BAD DEBT EXPENSE		0
REVENUE TAX:		
Increase in Operating Revenues		89,841
Less: Increase in Bad Debt Expense		0
		89,841
PSC Tax & PUC Fees Rate	x	6.385%
		5,736
Increase in Electric Revenues		89,711
Less: Increase in Bad Debt Expense		0
		89,711
Franchise Tax Rate	x	2.500%
		2,243
INCREASE IN REVENUE TAX		7,979
INCOME TAX:		
Increase in Operating Revenues		89,841
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.454%
INCREASE IN INCOME TAX		31,852
INCREASE IN OPERATING INCOME (check)		50,010

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	7,979	22	(29)	(634)
Income Tax at curr eff rate	(8,578)	(24)	(2)	(47)
Income Tax at proposed rate	23,274	64	(2)	(128)
CHANGE IN RATE BASE - WORKING CASH				(809)
Rate Base at Current Effective Rates				1,253,611
PROPOSED RATE BASE				1,252,802
Operating Income at Current Effective Rates				61,115
Increase in Operating Income				50,009
OPERATING INCOME AT PROPOSED RATES				111,124
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.87%

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
SUPPORT WORKSHEET
2009

OPERATING REVENUES:	
Electric Sales Revenues	1,291,619
Other Operating Revenues	4,140
Gain on Sale of Land	615
TOTAL OPERATING REVENUES	1,296,374
FUEL OIL AND PURCHASE POWER EXPENSES:	
Fuel Oil Expense	431,206
Fuel Related Non-labor Exp	6,549
Fuel Handling Labor Expense	593
Fuel Oil Expense	438,348
Purchased Power Expense	346,467
TOTAL FUEL OIL AND PURCHASE POWER EXPENSES	784,815
OTHER OPERATION & MAINTENANCE EXPENSES:	
Production	78,973
Transmission	13,859
Distribution	29,844
Customer Account	12,500
Allowance for Uncollectible Accounts	1,302
Customer Service	6,558
Administration & General	88,948
TOTAL OTHER OPERATION & MAINTENANCE EXPENSES	231,984

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
SUPPORT WORKSHEET
2009

TOTAL FUEL OIL & PP AND OTH O&M EXPENSES (LABOR/NONLABOR)		
Fuel Oil Expense		431,206
Purchase Power Expense		346,467
Total Labor Expense		
Labor Expense		99,620
Total Labor Expense		99,620
Total Nonlabor Expense		
Nonlabor Expense		132,957
Fuel Related Expense		6,549
Payroll Taxes		7,194
Bad Debt Expense		(1,302)
Pension Expense & Amortization		(22,274)
		123,124
TOTAL FUEL OIL & PP, OTH O&M AND PR TAX EXPENSES		1,000,417
REVENUE TAX		
Public Service Tax		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
Public Service Tax Rate	x	5.885%
Total PSC Tax		76,179
PUC Fees		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
PUC Tax Rate	x	0.500%
Total PUC Tax		6,472

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
SUPPORT WORKSHEET
2009

Franchise Tax		
Electric Sales Revenues		1,291,619
Less: Bad Debt Expense		(1,302)
		1,290,317
Franchise Tax Rate	x	2.500%
Total Franchise Tax		32,258
TOTAL REVENUE TAX		114,909
INTEREST EXPENSE:		
Weighted Cost of Debt		
Short-Term Debt		0.000%
Long-Term Debt		2.368%
Hybrid Securities		0.146%
Total		2.514%
Rate Base at Proposed Rates	x	1,252,802
TOTAL INTEREST EXPENSE		31,495
INCOME TAX EXPENSE SUMMARY		
Current		(8,578)
Deferred		24,041
State ITC		0
TOTAL INCOME TAX EXPENSE		15,463
CALCULATIONS OF REVENUE TAX RATE:		
Franchise Tax Rate adjusted for Change in Oth Oper Revenues and Bad Debt		0.02496
PSC Tax Rate adjusted for Bad Debt		0.05885
PUC Tax Rate adjusted for Bad Debt		0.00500
REVENUE TAX RATE		0.08881
CALCULATIONS OF COMPOSITE INCOME TAX RATE:		
State Tax Rate		0.06015
Federal Tax Rate		0.35000
State Tax Rate		0.06015
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Tax		(0.02105)
COMPOSITE INCOME TAX RATE		0.38910

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% at Curr Eff Rates
SUPPORT WORKSHEET
2009

CALCULATIONS OF COMPOSITE CAPITAL GAINS TAX RATE:		
State Capital Gains Tax Rate		0.03759
Federal Tax Rate		0.35000
State Capital Gains Tax Rate		0.03759
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Capital Gains Tax Rate		(0.01316)
COMPOSITE CAPITAL GAINS TAX RATE		0.37444
CALCULATIONS OF EFFECTIVE INCOME TAX RATE:		
PSC Tax & PUC Fees Rates adjusted for Bad Debt		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev and Bad Debt		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Revenue Tax and Bad Debt rate		0.08881
Rev Tax & Bad Debt Reciprocal	(1 - 0.08881)	0.91119
Composite Income Tax Rate	x	0.38910
EFFECTIVE INCOME TAX RATE AFTER CONSIDERING REVENUE TAX & BAD DEBT		0.35454
CALCULATIONS OF OPERATING INCOME DIVISOR:		
PSC Tax & PUC Fees Rates		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Effective Income Tax Rate after considering revenue tax & bad debt		0.35454
		0.44335
OPERATING INCOME DIVISOR	(1 - 0.44335)	0.55665

Hawaiian Electric Company, Inc.
Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.87% Return on Average Rate Base
Electric Sales Revenue	1,291,619	88,861	1,380,480
Other Operating Revenue	4,140	130	4,270
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	88,991	1,385,365
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	5,784		5,784
Administration & General	88,948		88,948
Operation and Maintenance	1,016,025	0	1,016,025
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,904	130,007
Interest on Customer Deposits	479		479
Income Taxes	15,765	31,551	47,316
TOTAL OPERATING EXPENSES	1,234,787	39,455	1,274,242
OPERATING INCOME	61,587	49,536	111,123
AVERAGE RATE BASE	1,253,601	(801)	1,252,800
RATE OF RETURN ON AVERAGE RATE BASE	4.91%		8.87%

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2009 Average

	A	B	C	D
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)
Short-Term Debt	0	0	0.75%	0.000%
Long-Term Debt	576,569	40.76	5.81%	2.368%
Hybrid Securities	27,775	1.96	7.41%	0.146%
Preferred Stock	20,696	1.46	5.48%	0.080%
Common Equity	789,374	55.81	11.25%	6.279%
Total	1,414,414	100.00		
Estimated Composite Cost of Capital				8.873%
			or	8.87%

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
2009 AVERAGE RATE BASE
($ Thousands)

	Beginning Balance	End of Year Balance	Average Balance
Investments in Assets Serving Customers			
Net Cost of Plant in Service	1,365,578	1,575,485	1,470,532
Property Held for Future Use	2,331	2,331	2,331
Fuel Inventory	43,274	46,736	45,005
Materials & Supplies Inventories	16,391	16,015	16,203
Unamort. Net SFAS 109 Reg. Asset	57,753	62,718	60,236
Unamort Sys Dev Costs	4,684	7,936	6,310
RO Pipeline Reg Asset	0	6,366	3,183
ARO Reg Asset	10	12	11
Total Investments in Assets	1,490,021	1,717,599	1,603,811
Funds From Non-Investors			
Unamortized CIAC	178,757	183,375	181,066
Customer Advances	947	807	877
Customer Deposits	8,201	8,581	8,391
Accumulated Def. Income Taxes	132,510	156,551	144,531
Unamort State ITC (Gross)	30,102	28,650	29,376
Unamortized Gain on Sale	1,345	746	1,046
Pension Reg Liability	3,051	-3,454	-202
OPEB Reg Liability	777	433	605
Total Deductions	355,690	375,689	365,690
Difference			1,238,121
Working Cash at Current Effective Rates			15,480
Rate Base at Current Effective Rates			1,253,601
Change in Rate Base - Working Cash			(801)
Rate Base at Proposed Rates			1,252,800

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
WORKING CASH ITEMS
2009
($ Thousands)

	A COLLECTION LAG (DAYS)	B PAYMENT LAG (DAYS)	C NET COLLECTION LAG (DAYS) (A - B)	D ANNUAL AMOUNT
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	37	17	20	431,206
O&M Labor	37	11	26	99,620
O&M Nonlabor	37	33	4	122,350
ITEMS THAT PROVIDE WORKING CASH				
Revenue Taxes	37	66	(29)	114,909
Income Taxes-Curr Eff Rates	37	39	(2)	(8,276)
Income Taxes-Proposed Rates	37	39	(2)	23,275
Purchased Power	37	37	0	346,467

	E AVERAGE DAILY AMOUNT (D/365)	F WORKING CASH (CURR EFF RATES) (C X E)	G AVERAGE DAILY AMOUNT (PROPOSED)	H WORKING CASH (PROPOSED RATES) (C X G)
ITEMS REQUIRING WORKING CASH				
Fuel Oil Purchases	1,181	23,628	1,181	23,628
O&M Labor	273	7,096	273	7,096
O&M Nonlabor	335	1,341	335	1,341
ITEMS THAT PROVIDE WORKING CASH				
Purchased Power	949	0	949	0
Revenue Taxes	315	(9,130)	336	(9,758)
Income Taxes-Curr Eff Rates	(23)	45		
Income Taxes-Proposed Rates	64	-	64	(128)
Settlement Adjustment		(7,500)		(7,500)
Total		15,480		14,679
Change in Working Cash				(801)

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
COMPUTATION OF INCOME TAX EXPENSE
2009
($ Thousands)

	Current Effective Rates	Adjustment	At Proposed Rates
Operating Revenues	1,296,374	88,991	1,385,365
Operating Expenses:			
Fuel Oil and Purchased Power	784,815		784,815
Other Operation & Maintenance Expense	231,210	0	231,210
Depreciation	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other than Income	122,103	7,904	130,007
Interest on Customer Deposits	479		479
Total Operating Expenses	1,219,022	7,904	1,226,926
Operating Income Before Income Taxes	77,352	81,087	158,439
Tax Adjustments:			
Interest Expense	(31,495)		(31,495)
Meals and Entertainment	78		78
	(31,417)	0	(31,417)
Taxable Income at Ordinary Rates	45,935	81,087	127,022
Income Tax Exp at Ordinary Rates	17,873	31,551	49,424
Tax Benefit of Domestic Production Activities Deduction	1,870		1,870
Tax Effect of Deductible Preferred Stock Dividends	23		23
R&D Credit	215		215
TOTAL INCOME TAX EXPENSE	15,765	31,551	47,316

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
COMPUTATION OF TAXES OTHER THAN INCOME TAX
2009
($ Thousands)

	Rate	Current Effective Rates	Adjustment	At Proposed Rates
Electric Sales Revenue		1,291,619	88,861	1,380,480
Other Operating Revenue		4,140	130	4,270
Operating Revenues		1,295,759	88,991	1,384,750
Public Service Tax	5.885%	76,179	5,237	81,416
PUC Fees	0.500%	6,472	445	6,917
Franchise Tax	2.500%	32,258	2,222	34,480
Payroll Tax		7,194		7,194
TOTAL TAXES OTHER THAN INCOME TAX		122,103	7,904	130,007

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

OPERATING INCOME AT CURRENT EFFECTIVE RATES:		
Operating Revenues		1,296,374
Fuel and Purchased Power Expenses		784,815
Other O&M Expenses		231,210
Depreciation & Amortization Expense		81,868
Amortization of State ITC		(1,453)
Taxes Other than Income		122,103
Interest on Customer Deposits		479
Income Taxes		15,765
Total Operating Expenses		1,234,787
OPERATING INCOME AT CURRENT EFFECTIVE RATES		61,587
CALCULATIONS OF REVENUE REQUIREMENTS:		
OPERATING INCOME		
Rate Base at Proposed Rates		1,252,800
Proposed Rate of Return on Rate Base	x	8.87%
Operating Income		111,123
Less: Operating Income at Current Effective Rate		61,587
INCREASE IN OPERATING INCOME		49,536
OPERATING REVENUES:		
Increase in Operating Income		49,536
Operating Income Divisor	(divided by)	0.55665
INCREASE IN OPERATING REVENUES		88,991
Increase in Electric Sales Revenue		88,861
Other Operating Revenue Rate	x	0.146%
Increase in Other Operating Revenues		130
		88,991

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

BAD DEBT:		
Increase in Electric Revenues		88,861
Bad Debt Rate	x	0.0000
INCREASE IN BAD DEBT EXPENSE		0
REVENUE TAX:		
Increase in Operating Revenues		88,991
Less: Increase in Bad Debt Expense		0
		88,991
PSC Tax & PUC Fees Rate	x	6.385%
		5,682
Increase in Electric Revenues		88,861
Less: Increase in Bad Debt Expense		0
		88,861
Franchise Tax Rate	x	2.500%
		2,222
INCREASE IN REVENUE TAX		7,904
INCOME TAX:		
Increase in Operating Revenues		88,991
Effective Income Tax Rate after considering revenue tax & bad debt	x	35.454%
INCREASE IN INCOME TAX		31,551
INCREASE IN OPERATING INCOME (check)		49,536

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
CALCULATIONS OF REVENUE REQUIREMENTS
2009
($ Thousands)

CHANGE IN RATE BASE:

	A EXPENSE AMOUNT	B AVERAGE DAILY AMOUNT (A/365)	C NET COLLECTION LAG (DAYS)	D WORKING CASH REQMT (B)x(C)
Increase in Revenue Tax	7,904	22	(29)	(628)
Income Tax at curr eff rate	(8,276)	(23)	(2)	(45)
Income Tax at proposed rate	23,275	64	(2)	(128)
CHANGE IN RATE BASE - WORKING CASH				(801)
Rate Base at Current Effective Rates				1,253,601
PROPOSED RATE BASE				1,252,800
Operating Income at Current Effective Rates				61,587
Increase in Operating Income				49,536
OPERATING INCOME AT PROPOSED RATES				111,123
PROPOSED RATE OF RETURN ON RATE BASE (check)				8.87%

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

OPERATING REVENUES:	
Electric Sales Revenues	1,291,619
Other Operating Revenues	4,140
Gain on Sale of Land	615
TOTAL OPERATING REVENUES	1,296,374
FUEL OIL AND PURCHASE POWER EXPENSES:	
Fuel Oil Expense	431,206
Fuel Related Non-labor Exp	6,549
Fuel Handling Labor Expense	593
Fuel Oil Expense	438,348
Purchased Power Expense	346,467
TOTAL FUEL OIL AND PURCHASE POWER EXPENSES	784,815
OTHER OPERATION & MAINTENANCE EXPENSES:	
Production	78,973
Transmission	13,859
Distribution	29,844
Customer Account	12,500
Allowance for Uncollectible Accounts	1,302
Customer Service	5,784
Administration & General	88,948
TOTAL OTHER OPERATION & MAINTENANCE EXPENSES	231,210

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

TOTAL FUEL OIL & PP AND OTH O&M EXPENSES (LABOR/NONLABOR)		
Fuel Oil Expense		431,206
Purchase Power Expense		346,467
Total Labor Expense		
Labor Expense		99,620
Total Labor Expense		99,620
Total Nonlabor Expense		
Nonlabor Expense		132,183
Fuel Related Expense		6,549
Payroll Taxes		7,194
Bad Debt Expense		(1,302)
Pension Expense & Amortization		(22,274)
		122,350
TOTAL FUEL OIL & PP, OTH O&M AND PR TAX EXPENSES		999,643
REVENUE TAX		
Public Service Tax		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
Public Service Tax Rate	x	5.885%
Total PSC Tax		76,179
PUC Fees		
Electric Sales Revenues		1,291,619
Other Operating Revenues		4,140
Less: Bad Debt Expense		(1,302)
Operating Revenues subject to PSC Tax		1,294,457
PUC Tax Rate	x	0.500%
Total PUC Tax		6,472

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

Franchise Tax		
Electric Sales Revenues		1,291,619
Less: Bad Debt Expense		(1,302)
		1,290,317
Franchise Tax Rate	x	2.500%
Total Franchise Tax		32,258
TOTAL REVENUE TAX		114,909
INTEREST EXPENSE:		
Weighted Cost of Debt		
Short-Term Debt		0.000%
Long-Term Debt		2.368%
Hybrid Securities		0.146%
Total		2.514%
Rate Base at Proposed Rates	x	1,252,800
TOTAL INTEREST EXPENSE		31,495
INCOME TAX EXPENSE SUMMARY		
Current		(8,276)
Deferred		24,041
State ITC		0
TOTAL INCOME TAX EXPENSE		15,765
CALCULATIONS OF REVENUE TAX RATE:		
Franchise Tax Rate adjusted for Change in Oth Oper Revenues and Bad Debt		0.02496
PSC Tax Rate adjusted for Bad Debt		0.05885
PUC Tax Rate adjusted for Bad Debt		0.00500
REVENUE TAX RATE		0.08881
CALCULATIONS OF COMPOSITE INCOME TAX RATE:		
State Tax Rate		0.06015
Federal Tax Rate		0.35000
State Tax Rate		0.06015
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Tax		(0.02105)
COMPOSITE INCOME TAX RATE		0.38910

Hawaiian Electric Company, Inc.

Rebuttal at 11.25% w/o Advertising at Curr Eff Rates
SUPPORT WORKSHEET
2009

CALCULATIONS OF COMPOSITE CAPITAL GAINS TAX RATE:		
State Capital Gains Tax Rate		0.03759
Federal Tax Rate		0.35000
State Capital Gains Tax Rate		0.03759
Federal Tax Rate	x	0.35000
Federal Tax Effect on State Capital Gains Tax Rate		(0.01316)
COMPOSITE CAPITAL GAINS TAX RATE		0.37444
CALCULATIONS OF EFFECTIVE INCOME TAX RATE:		
PSC Tax & PUC Fees Rates adjusted for Bad Debt		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev and Bad Debt		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Revenue Tax and Bad Debt rate		0.08881
Rev Tax & Bad Debt Reciprocal (1 - 0.08881)		0.91119
Composite Income Tax Rate	x	0.38910
EFFECTIVE INCOME TAX RATE AFTER CONSIDERING REVENUE TAX & BAD DEBT		0.35454
CALCULATIONS OF OPERATING INCOME DIVISOR:		
PSC Tax & PUC Fees Rates		0.06385
Franchise Tax adjusted for Change in Oth Oper Rev		0.02496
Bad Debt Rate adjusted for Change in Oth Oper Rev		-
Effective Income Tax Rate after considering revenue tax & bad debt		0.35454
		0.44335
OPERATING INCOME DIVISOR (1 - 0.44335)		0.55665